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# GENERATION ADEQUACY METHODOLOGIES REVIEW

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**Abstract**

Generation adequacy is a key tool to assess security of supply in an electrical system. In Europe, the integration of high amount of variable generation, demand response, storage, distributed generation, the increase of interconnection capacities and the electricity markets coupling, motivate a need for a revision of how adequacy is assessed. This work presents a review of some European Member States, regions and ENTSO-E's pan-European methodologies to highlight the latest developments and current trends.

**Title** Generation Adequacy methodologies review

We examine a set of generation adequacy methodologies in Europe to highlight the latest developments and current trends.

- We show that regional and pan-European assessments are used to reveal the situation of an integrated functioning of the European electricity system and market.
- The scope of national, regional and Pan-European assessments shall be established to obtain a minimum harmonization of the regulatory framework and methods.
- Capacity assessments should be complemented with further assessments (e.g. flexibility) as variable renewable energy penetration increases.

# GENERATION ADEQUACY METHODOLOGIES REVIEW

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# Executive summary

## Policy context

The European electricity system is undergoing profound modifications and will continue to do so in the foreseeable future. The challenge is to keep the system working properly while these changes take place. Generation adequacy is the ability of the generation in the power system to match the load on the power system at all times. **Generation adequacy** analysis is important for energy consumers because it seeks to demonstrate whether the electricity supply is able to remain secure and available when needed. A coherent methodology to assess adequacy is important to facilitate the planning process of new energy supply facilities to deliver energy and, at the same time, avoid overinvestment which unavoidably results in an increase of the energy price. Recently, adequacy was mainly an issue dealt with at the national level. However, the increasing physical/power interconnection/exchange among the national electricity systems, as well as the steps taken towards the single electricity market in Europe, motivate a review of the adequacy assessment methodology. Other important elements that are driving this change include: the rising amount of variable renewable energy generation (steering greater flexibility needs), the current financial profitability of gas power plants (leading to longer and/or more frequent mothballing periods), and the decommissioning of old power plants (threatening security of supply in some countries due to perspective capacity deficit). This intricate situation, with manifold potential critical impacts, has led to the proposal of **capacity remuneration mechanisms** in several European countries. At the European level, all these elements shall be eventually framed in the context of the Energy Union initiatives which are bringing about deep revisions and changes in the **electricity market** and the carbon emissions trade.

Against this background, the JRC has been mandated by DG ENER to analyse existing generation adequacy assessments produced by Member States and ENTSO-E, in order to support policy decision-making on a European.framework for the assessment of generation adequacy. Particularly, the focus of this report is to compare Generation Adequacy reports, in selected Member States, regions (i.e. clusters of Member States) and at the pan-European level, in order to identify strengths and weaknesses, highlight best practices and propose methodological recommendations.

This methodological review was carried out under the Administrative Arrangement No ENER/B2/FV2014-742/SI2.702110 — AA JRC between DG Energy and DG Joint Research Centre related to the definition of a methodology for generation adequacy in the EU.

## Key conclusions

Complementing national adequacy assessments with regional and pan-European studies is required for scrutinising the integrated interplay and functioning of the European electricity system and market. To this end, a minimum harmonisation of the regulatory frameworks and of the assessment procedures is vital to obtain comparable results and to consistently support the decision-making across countries. What is needed, besides a minimum harmonisation of models and data inputs, is to clearly determine what the scope of each assessment is. Indeed, increasing the model geographical size can be hardly attained at the same time as increasing the time resolution, as well as representing into detail several other system features: this is not only due to the computational constraints to run the simulations but also to the growing complexity of the models to be used for supporting decision-making; additionally, keeping things as simple as possible will avoid constant revisions of the fundamentals and the basic assumptions of the assessment methodologies used by a vast number of stakeholders.

The evolution of the electrical system poses a number of challenges to traditional generation adequacy assessments. A well-recognised instance is flexibility (capacity of the system to cover fast and deep changes in the net demand) whose importance is growing along with the penetration of variable energy generation and the need to compensate for its rapid and less controllable fluctuations. In this view generation adequacy assessment shall include a flexibility assessment, where demand side management and/or storage mainly operate during hours of peak demand or high ramping requirements. Cross-border interconnections play also a fundamental role in the integration of renewable energy, in supporting peak

demand and in contributing to the overall system adequacy safeguard, provided that collaborative and solidarity mechanisms among Member States are further promoted and implemented.

## Main findings

Although a very heterogeneous picture in generation adequacy assessment methodologies is observed, some common trends can also be highlighted:

- Whilst generation adequacy has been typically carried out by assessing the capacity resources at peak demand, future planning processes requires not only to estimate capacity needs but also other inherent, dynamic characteristics of the generating units. As a matter of fact, the integration of high amounts of variable generation is shifting the periods where more system flexibility is required, from peak demand to time periods where the residual load (given by the power demand minus non-dispatchable energy generation, mainly wind and PV) changes more swiftly and steeply, thus increasing the generation cycling and ramping (up and down) requirements.
- Member States and ENTSO-E are moving from deterministic power balance to probabilistic assessment approaches.
- TSOs have become aware that demand forecast based only on GDP evolution is no longer valid. Many other factors should be considered, as for example, energy efficiency programs, electrification of some applications (mainly heat pumps for heating), new uses (electric cars) and so on.
- The evolution of the gas fleet is the most uncertain input data of the generation forecast. The number of mothballed power plants will depend on the evolution of demand, the oil and gas prices, the evolution of $CO_2$ emissions prices and the future market design. Also, the estimation of their future availabilities needs to be explored.
- Renewable energies (wind and solar PV) are no longer considered as not available capacities, although their contribution to resource adequacy is far from being harmonised.
- Distributed generation should be properly appraised due to its impact on the residual load profile.
- Modelling hydro power plants is also a complicated task but they are very relevant to reduce potential curtailment of renewables at times of overgeneration.
- Demand Side Response (DSR) is expected to play a much more important role in the near future in power system balancing and operation.
- Synchronous data are essential for temperature-sensitive load models, harmonised probabilistic hydrological data, and also to properly take into account spatial and temporal correlation among generation sources and demand.
- Reserves are an important balancing tool to cope with unexpected events occurring in the system. Their role is important also in the assessment of flexibility needs.
- 15-year-ahead time horizon is considered, in most cases, as a too long-term scenario to estimate future generation and demand scenarios since the uncertainties are high.

## Related and future JRC work

What is presented in this work reflects activities on energy security, systems and markets conducted at the JRC, the in-house scientific branch of the European Commission, providing scientific advice to the EU policy-making.

The JRC aims to support the European Commission's Energy Union strategy to make energy more secure, affordable and sustainable, and foster sustainable and efficient transport in Europe.

This work shall be considered in the framework of the other research activities on the evolving power system and markets, conducted at the JRC. They range from transmission to distribution systems, from wholesale to retail markets, from generation to consumers. Additional information can be found on the website http://ses.jrc.ec.europa.eu/

# 1. Introduction

## 1.1 Context

Today's European electricity market differs fundamentally from the market years ago. New climate and energy policies promoted at the European level and transposed by the Member States into national programs, together with the prolonged recession that has characterised European economies in the last 8 years and which has drastically dropped electricity demand, have set a profound change in the power sector. The main factors can be grouped as follows

- The need for long-term security of the energy supply

The long-term dimension of security of supply mainly deals with insuring timely investments to supply energy in line with economic developments and sustainable environmental needs. This need is challenged by the fact that European Member States rely on a high share of primary energy supply coming from non-EU countries. These two aspects together have driven national energy policies to support local primary energy sources and new generation technologies with the aim at decreasing the level of dependency from external energy sources.

- The ripple effect of climate and energy policies

Policies in support of low carbon generation have had outstanding success so far. Figure 1 the share in the installed capacity mix (MW) in Europe in 2000 and in 2014. Coal, combustible fuel and nuclear have been partially replaced by wind and solar capacity. Also the share of hydro has recorded a decrease of 4.3% in the considered period.

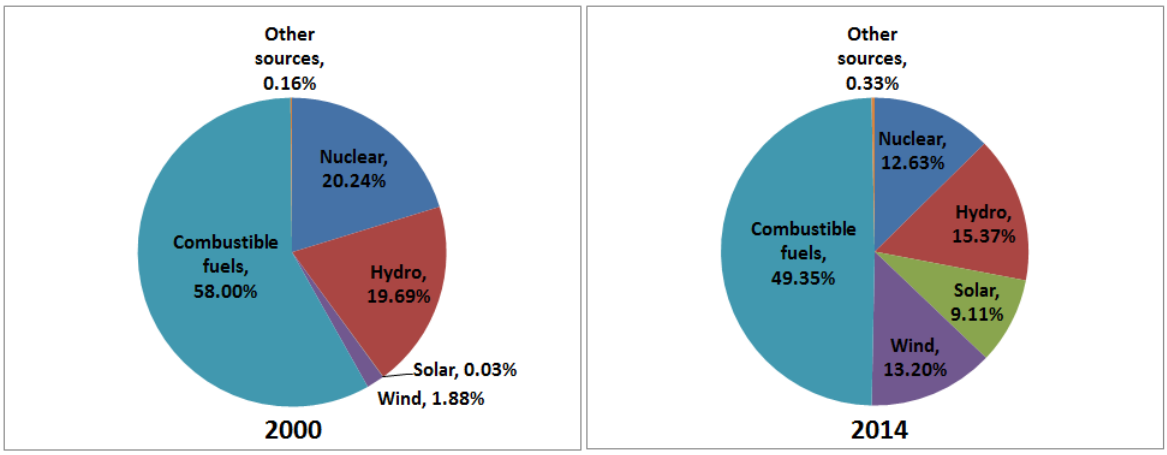



**Figure 1. Installed capacity mix (MW) in EU-28 (2000-2014).**
**Source: [1].**

- Price of hydrocarbons

The lower level of coal prices with respect to gas, together with the collapse of $CO_2$ emission prices has led to gas-fired generation becoming considerably more expensive than coal-fired generation; indeed a considerable number of gas power plants have requested a mothballing period.

- Electricity price drop

The EPEX spot day-ahead market average hourly price was 37.78 EUR/MWh in 2013 and 32.76 EUR/MWh in 2014. On the EEX derivatives market, the average was 39.08 and 35.09 EUR/MWh in 2013 and 2014 respectively ( [2]). These values are lower than the long-term cost of most of the generation technologies ( [3]).

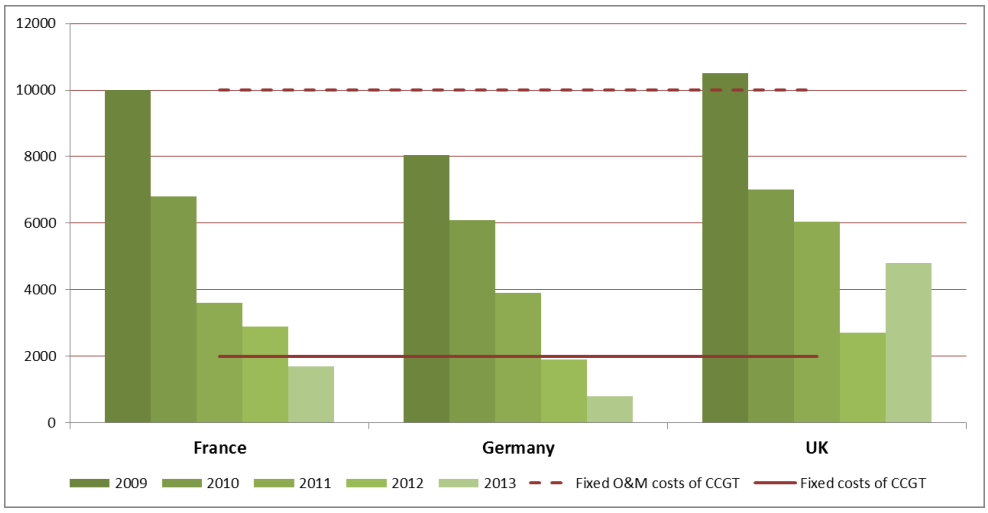



**Figure 2. Decrease in revenues of CCGT in 3 Member States (EUR/MW/month). Source: *Capacity Mechanisms, Reigniting Europe's energy markets*. [4]**

All of these profound changes in the power system situation did not come without consequences: on one side, thermal power sources have seen their business opportunities drastically worsen [4]. Between 2008 and 2013, the average utilisation rate of thermal plants dropped from 50% to 37% (Figure 2). This was also due to the drop in power demand. On the other side, fluctuation and uncertainty of renewable resources posed new challenges both in terms of their integration in the power system and reliability of the infrastructure.

Generation adequacy together with secure primary resources and the mitigation of intermittency coming from renewables represent key aspects of this new setting that require an evolution and coordination of regulatory and governance frameworks at EU and national level.

The adequate level of generation capacity needs to be assessed in light of the current transformation of the entire system, to avoid over-capacity and guarantee the right signals to efficient investments. But in the near future, not only an adequate level of capacity should be assured, but also that the system has enough mechanisms to be effectively operated to manage the intermittency of renewable energy generation.

Dispatchable generation power plants, together with other technologies like electricity storage and demand response, are considered an essential part of the technology mix to resolve periods of system stress caused by high renewable energy generation or high demand levels. New services provided by those flexible sources should be adequately valued in the market to give investors the right information on business opportunities. Right price signals would lead to the optimal level of thermal generation and other flexible technologies and thus insure adequacy ( [5]).

In this context the role of national public authorities in monitoring and ensuring security of supply, including generation adequacy, has become more and more important. The EU legislation (Directive 2009/72/EC and EU Directive 2005/89/EC) sets the obligation on each Member State to monitor the security of electricity supply [6], which includes generation planning within their territory over the medium to long term. At the same time, the integration of energy markets that allows power trades at least cost and more penetration of RES is bringing the discussion to the need for a coordinated approach among countries in the assessment of the adequate generation capacity at the regional level. Under the provisions of Council Regulation (EC) 714/2009, ENTSO-E carries out a nonbinding Generation Adequacy Assessment at Regional and European levels.

In the Communication 'Delivering the internal electricity market and making the most of public intervention', the Commission addressed the need for public authorities to regularly undertake an objective, facts-based assessment of the generation adequacy situation. The Commission is examining how ENTSO-E Union-wide generation adequacy could better meet future needs.

In this context of rapid changes, the European Electricity Market is currently under revision together with the EU Emissions Trading Scheme (ETS) and some Member States are putting into operation capacity mechanisms to ensure enough capacity in their systems. ENTSO-E is also updating the generation adequacy methodology to properly address future needs and to highlight the benefits of the pan-European assessment.

## 1.2 What is beyond the reliability of the power system

The main function of an electric power system is to provide energy to its customers with an acceptable level of quality and continuity. The electric power system is periodically planned in order to reduce the probability, duration and frequency of outages. Reliability issues are integral elements of the planning process. In electricity, reliability, also called security of supply, refers to two distinct but related aspects: security and adequacy (see Figure 3).

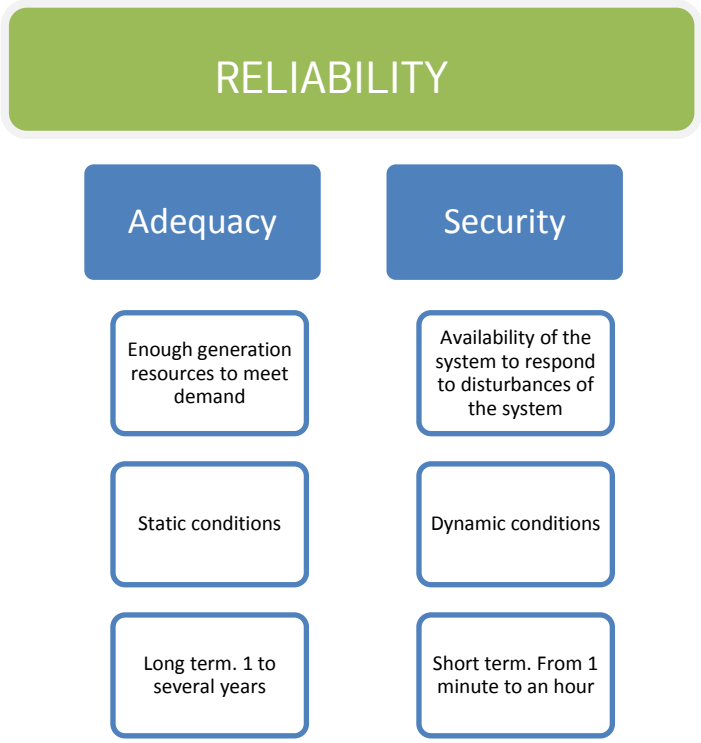



**Figure 3. Subdivision of System Reliability.**

Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and unscheduled outages of system facilities [7].

A number of events can undermine the reliability of the system, as for example the occurrence of congestions in the grid, the sudden interruption of power generation or an unexpected increase in power demand. Any improvements in the reliability of the system do not come without a cost. So, in the decision planning process, the main objective is to balance the benefits realised from providing higher reliability with the cost of procuring it (Figure 4), taking into account that the marginal cost of reliability increases (see Figure 5).

It should be mentioned that this optimisation exercise is not simple. A key question in this analysis is that the cost borne by the consumers in case of disruptions is assessed through the VOLL (Value of Lost Load) which is an estimation of the consumers' willingness to pay to avoid an additional period without power (see, for example, the discussion in [8] or [9]).

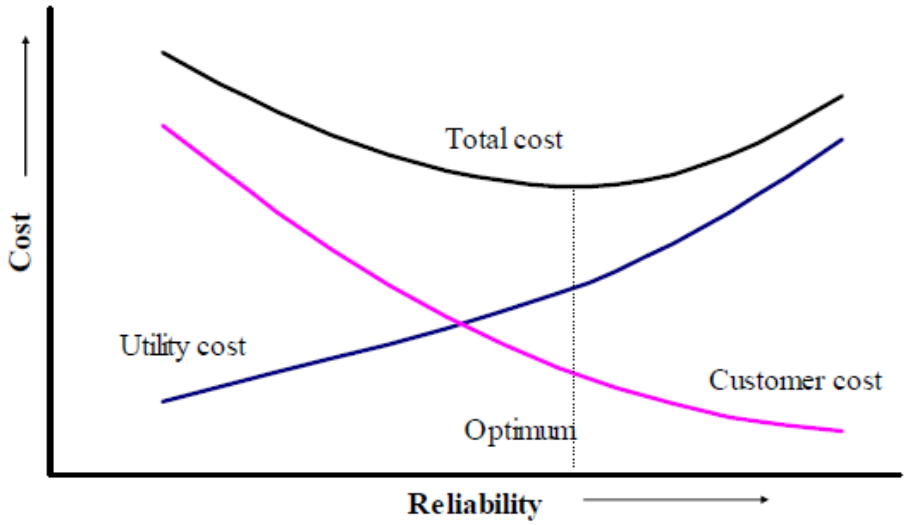



**Figure 4. Cost versus reliability curves.**

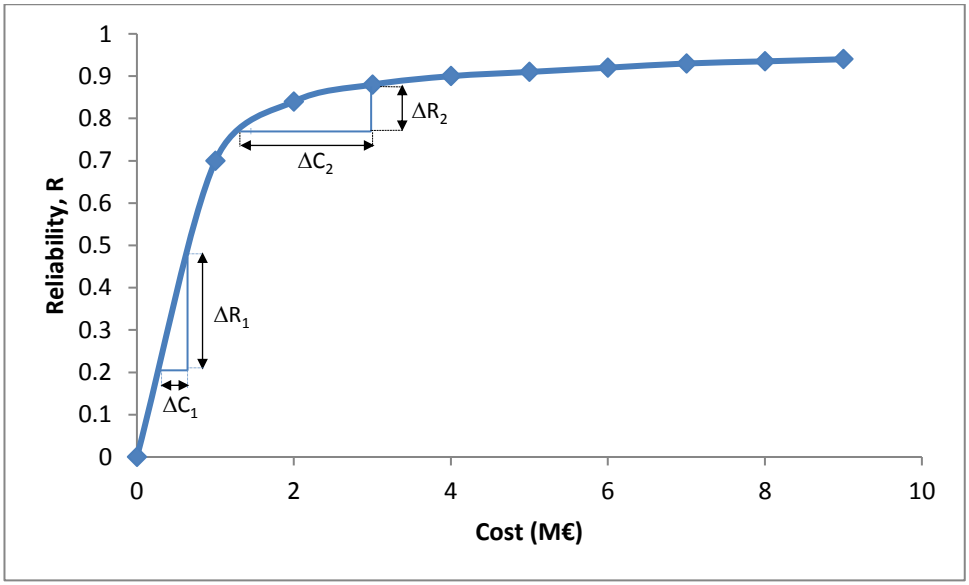



**Figure 5. Incremental cost of reliability.**

Due to the complexity of the power system and its dimension, the traditional way of ensuring adequacy was to independently consider generation, transmission and distribution and based on deterministic approaches. This was because power systems were not very interconnected, the generation was mainly dispatchable and all the uncertainties were either the error in the forecast demand, that traditionally was very low, or sudden failures in generators or other elements in the systems (lines, transformers, etc.).

The current situation is characterised by highly interconnected systems that leads to a huge power system dimension, the larger amount of renewable energy integrated into the electricity system, new technologies (storage, demand side response, DSM, etc.) and evolving policies. These new elements trigger the need for a more adjusted approach but also requires special coordination efforts to improve the methodologies and a common understanding of the new challenges in the generation adequacy assessment. More than ever, generation adequacy deals with different aspects:

- Optimal level of generation capacity. In this regard, [10] entails the following questions:
  - ✓ Promote (local) generation or increase interconnection capacity?
  - ✓ Promote generation or promote demand response?

In other words, there are currently additional resources for coping with 'generation' adequacy (although they are not generators).

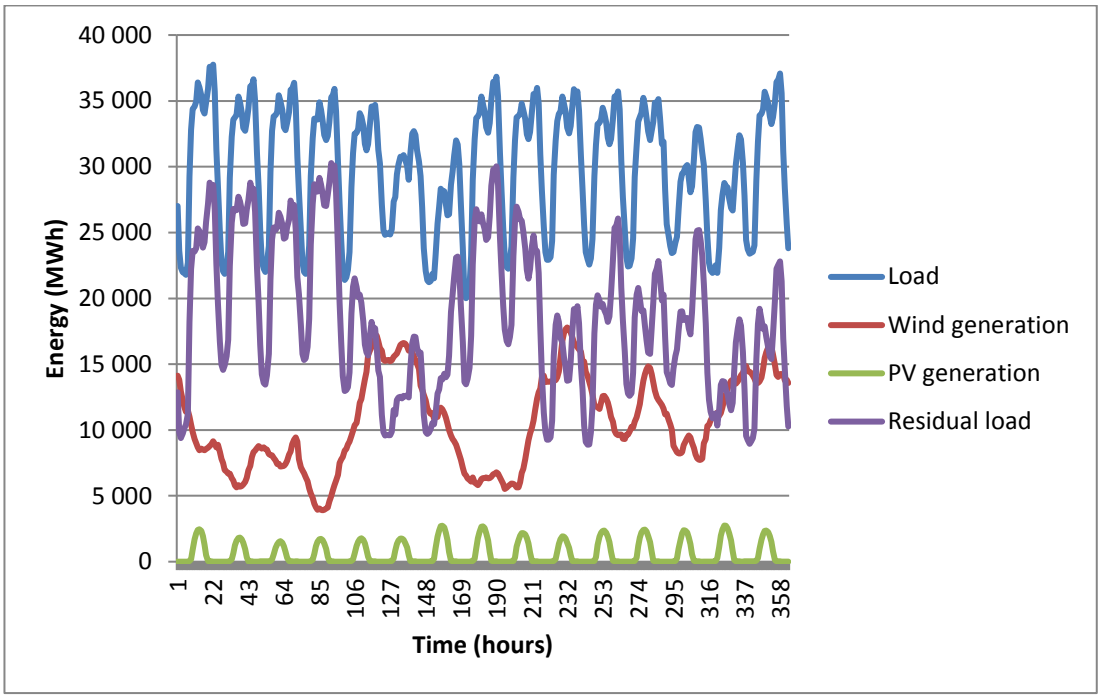



**Figure 6. Daily patterns of electricity demand versus residual load.**
**Source: Own analysis for Spain.**
**Data from REE 28.1.2013 to 11.2.2013.**

- Optimal mix of different technologies:
- In terms of residual load (also called net demand) — given by the power demand minus non-dispatchable energy generation (mainly, wind and PV) —featuring unpredictable trends which need deeper ramp-up and ramp-down requirements (see Figure 6). In this context the solution should be the optimal mix of base and peak generators, cross-border capacity, storage and demand response.
- In terms of fuel mix (magnitude of the different risks associated with their supply, depending on the importer's countries).
- Optimal sustainability of the solution.

All of the above-mentioned elements pose a number of challenges to traditional generation adequacy assessments. A well-recognised instance is flexibility (capacity of the system to cover fast and deep changes in the net demand) whose importance is growing along with the penetration of non-dispatchable energy generation and the need to compensate for its rapid and uncontrollable fluctuations. In this view, generation adequacy assessment shall include a flexibility assessment, where DSM and/or storage mainly operate during hours of peak demand or high ramping requirements. Cross-border interconnections play also a fundamental role in the integration of renewable energy, participation in the generation adequacy among interconnected countries and support of peak demand hours with power imports. This means that the two elements of reliability (adequacy and security, see Figure 3) overlap more and more.

## 1.3 Main elements of generation adequacy assessments.

The main elements to a comprehensive generation adequacy evaluation can be summarised in three points (see [11]):

- Build a model of supply, where the generation capacity fleet is modelled upon the operating characteristics of the generating technologies. This section includes assumptions on the units operating at the time of the assessment and future new investments and decommissioning.
- Build a model of demand that is aimed at incorporating present and future characteristics of the consumptions trend which is built upon forecasts and estimations of the main variables that affect power consumption.
- Build a risk model that integrates the generation and load model, to estimate system reliability indices [12].

Traditional assessment methodologies of the generation adequacy in vertically integrated structure of the electricity systems would handle the flexibility requirements through internally controlled adjustment of supply by the system operator. With market liberalisation and the profound change of the structure of the generation sector, adequacy (and flexibility) issues will require the active participation of all relevant elements present in the system (generators, storage, interconnectors, demand response, etc.).

The objective of the GA evaluation is to get a measurement of the overall adequacy of the system while abstracting from congestions, voltage drops and frequency problems of the grid. An exception is generation adequacy methodologies which include cross-border capacities as they should be properly modelled.

## 1.4 Methodologies

Methodologies in this field distinguish between determinist and probabilistic techniques. They differ from the mathematical procedure and from the risk indexes calculated to measure the reliability of the system.

Deterministic approaches estimate the availability of generation at some time point in the future (usually winter and summer peak demand). Their essential weakness is that they do not capture the inherent and irreducible uncertainty of the stochastic variables and do not consider wind and solar energy as capacity value generators.

Probabilistic approaches estimate the probability of the system of being unable to supply demand considering variabilities and uncertainties associated with the energy resources and the demand. Techniques in this field can be classified into two categories: analytical methods and Monte Carlo simulation methods. Analytical methods are based on models assuming some probability distribution functions for the different elements of the system and then combine the probabilities and frequencies of system states to arrive at the reliability indices. Monte Carlo procedures can be classified in non-sequential or sequential procedures. A non-sequential process (or time-collapsed model) investigates the probability distribution of the margin of available supply over demand at multiple, independent, randomly chosen points in time. Sequential techniques consider the operating cycle of all the components of the system. The sequential simulation methods provide additional time-related indices such as frequency and duration of load loss and they are the only methodological procedures that will be able to cover flexibility issues. Although they have been acknowledged since the 1930s, its real application is still not sufficiently widespread.

## 1.5 Reliability indices

Each index is suited to reflect a particular reliability issue but there is not a perfect index that can cover all the reliability characteristics of a system. Indices can be classified, as models, in deterministic and probabilistic. Very good discussions about the different indices are found in [9] and [12].

Deterministic metrics:

- Reserve Margin (RM). It is the most common deterministic index. It is a measurement of the available capacity excess with respect to the foreseen demand. It is defined as the difference between the total available generating capacity and the peak load divided by the peak load.
- Coverage Index (CI). It is also a deterministic metric. It is the ration between the available generation capacity and the peak load.
- Largest unit (LU). This method compares the difference between the total installed capacity and the peak load with the largest installed unit on the system.

Probabilistic metrics

- Loss of load probability (LOLP) is defined as the proportion of days or hours per year with insufficient available generating capacity.
- Loss of Load Expectation (LOLE) is the expected number of hours (days) per year in which there will be not enough available generation capacity to supply demand. It is the most used indicator in Europe.
- Forced Outage Probability (FOP) is the probability that a generator is out of service for reasons other than scheduled maintenance. This means that the available capacity of the system is the aggregate of generators' availabilities, each of them dependent on its FOP.
- Expected Energy Not Supplied (EENS) is the expected amount of energy that will not be supplied due to shortages or deficiencies in available generation capacity. It gives information regarding the number of shortages and their magnitude, and it is a very meaningful parameter for energy-limited technologies such as wind, solar or hydro.
- Loss of Energy Probability (LOEP). As EENS is measured in units of energy and depends on the size of the system, LOEP is the ratio between EENS and the total energy demanded, so it is independent of the size of the system and it can be used to compare different system performances.

## 1.6 Objectives of this report

This report consists of a review and comparison of the current methodologies adopted by some Member States of the European Union and the current and target methodology of ENTSO-E with the objective to identify the strengths and weaknesses of the approaches and to identify possible gaps.

The second main goal is to show the key issues that the generation and flexibility adequacy contain in order to inform policy-makers about the implications of current or potential future policies. This objective is based on the evidence that regulatory instruments that are introduced in the market — like capacity mechanisms, balancing responsibilities, market coupling and cross-border participation — all affect the estimation of generation adequacy of a power system.

## 1.7 Structure of the report

This report is organized as follows. Chapter 2 presents the generation adequacy methodology implemented by a selected number of European Member States and regions (Pentalateral Energy Forum), and ENTSO-E current and target methodologies. Chapter 3 shows a comparison among all the methodologies described in Chapter 2 and finally, Chapter 4 summarises the main findings and addresses future perspectives and further analysis.

# 2. Member States methodology review

## 2.1 Introduction

The objective of this chapter is briefly describe the main characteristics of the different Member States' methodologies and ENTSO-E's current and target methodologies. As generation adequacy is already a discussion topic there are some recent reviews, as for example [9], [6] and [13]. Nevertheless, the approach taken in this work is completely different as the focus is more on the details of the modelling activities and peculiarities of the mathematical procedures.

This work has been made by searching information publicly available on the internet. There are some limitations using this approach. First of all, not all the Member States have this information on a website, and secondly, the generation adequacy is sometimes an independent document or is part of other documents. Some Member States publish detailed information but others do not.

This report contains the review of the following Member States: Spain, Portugal, France, UK, Ireland, North Ireland, ENTSO-E and the Pentalateral Energy Forum.

Because generation mix, market design, and regulatory environments differ markedly, care is required in attempting to compare results between countries.

The review of the different approaches was done trying to reply to the following questions and factors:

- Who does the GAA?
- Who is it designed for?
- Last GAA published.
- Is GAA mandatory by law?
- Type of model.
- Last review of the methodology
- Periodicity.
- What is the time horizon?
- Time step in the model (time granularity).
- Model of demand. Weather normalisation.
- Model of supply.
- Consideration of reserves.
- Sources of data.
- Indicators (criteria used).
- Adequacy.
- Flexibility.
- Target value for the indicators.
- Scenarios.
- How they estimate uncertainty.
- Consideration of wind energy.
- Consideration of solar energy.
- Consideration of cross-border capacity.
- Consideration of storage.
- Consideration of demand side response.

- Consideration of distributed generation.
- How they consider correlation between demand and RES?
- Estimation of flexibility needs.
- Simplifications in the assessment (for example, do not consider summer).

The main steps for a comprehensive generation adequacy assessment are shown in Table 1.

| Model of demand | | Indicators |
|---|---|---|
| **Load** | The model of demand incorporates the current power consumption trends and estimates its future projections in order to provide sufficiently differentiated long-term scenarios of consumption. Uncertainties related to future economic growth and policy development regarding energy efficiency are included in the modelling, | —GDP scenarios<br>—Population growth<br>—Energy intensity of the economy<br>—NEEAP |
| **Weather conditions** | Thermo-sensitivity of the power demand. Temperature change has a great effect on the power consumption patterns, especially in the countries where electric heating is widely used. When assessing the security of supply correlation between weather conditions across countries shall be considered. | —Cold spells<br>—Peak demand in winter/summer |
| **Model of supply** | | **Indicators** |
| **Generation** | The model includes projections on the future installed capacity and the availability of the generation units. | —Installed capacities<br>—Availability<br>—Hydro profiles |
| **Renewables** | The model of supply includes information on current and future installed capacities and locations.<br>Consideration of RES as available generation.<br>Another aspect is to preserve the spatio-temporal correlation structure between demand, wind, solar and non-dispatchable hydro generation. | —Share of renewables in the generation mix<br>—Capacity credit<br>—Curtailment of renewable energy generation<br>—Indicators for flexibility |
| **Demand side response** | Demand side response (DSR) can potentially provide flexibility services to accommodate fluctuating power generation from renewables. DSR encompasses a wide range of different models and options, from switch-off contracts between large customers and TSOs to flexibility services provided by household appliances within a smart grid environment. | —DSM schemes<br>—Capacity for each scheme |
| **Storage** | In the times of electrical scarcity, storage can provide additional energy so that the supply can meet demand whenever needed. In the times of over-generation (typically days with low demand and high renewable generation), storage can avoid curtailment of RES generation. Energy storage can also coordinate power flows to maintain stability and reliability of system. The most common energy storage system used in EU Member States is pumped energy storage. | —Energy storage capacity (MWh)<br>—Peak power it can provide (MW) |
| **Cross-borders capacity** | Through interconnections each country shares — if available — its generation capacity with other countries thus leading to a (1) higher total available capacity in each country; (2) more efficient investment portfolio of generating plants; (3) additional source of flexibility given by the transfer capacity; (4) lower power prices when power markets are also coupled among countries.<br>Available capacity in the other country must be estimated.<br>Ignoring the interconnection capacity between Member States can lead to underestimation of the generation adequacy or the flexibility adequacy. | —Import/exports capacities in each country<br>—Available capacity in the other country |
| **Risk assessment** | | |
| **Indicators** | Risk is measured through the estimation of reliability indicators. There is no perfect index that can cover all the reliability characteristics of a system so a set of them are usually provided. The indicators are also compared with a target value which is supposed to indicate if the system is secure (adequate) or not. | |
| **Other recommended elements of the assessment** | | |
| **Sources of Flexibility** | High shares of non-dispatchable RES generation is increasing the flexibility needs of the system. This requires a two-step analysis: (1) the evaluation of the optimal mix of flexible sources that is needed; (2) the availability of the flexible sources at all times of imbalance. | |
| **Reserves** | The available generation shall cover the demand and the reserve needs for the secure operation of the system. Avoiding reserve needs estimation can lead to an underestimation of the future flexibility needs of the system. | |

**Table 1. Main elements of a generation adequacy assessment model.**

## 2.2 Spain

First of all it should be pointed out that the Spanish Transmission system is composed of the peninsular system and the non-peninsular systems (Balearic Islands, Canary Islands, Ceuta and Melilla). In this work the focus is only on the peninsular system adequacy, although the Spanish TSO performs the GAA for all the systems.

The GAA is done by REE, the Spanish TSO and included in the Network Development Plan Report. The electricity sector law (Law 24/2013 of 26 December) establishes in its Article 3 that The State Administration has the power to energy planning, in accordance with the terms set out in Article 4. Article 4 establishes that energy planning will be aimed to guarantee the needs of the electricity system in the long term as well as the necessary investment requirements in new transmission assets, based on the principles of transparency, and minimum cost for the system. Electricity generation is a free activity, consequently the plan is not mandatory for private investors, just indicative. However, in the case of the transmission grid development, the plan is legally binding.

The last report published is called 'Planificación de la red de Transporte de Energía Eléctrica 2015-2020' ( [14]). The generation adequacy is performed with a time horizon of 6 years and it must be done with a periodicity of at least 6 years.

### Methodology

Generation adequacy is assessed using a deterministic approach based on a power balance calculation. Power balance aims to estimate the coverage index at the moment of peak demand (maximum average hourly demand) at power station busbars for winter and summer. The coverage index (IC) is defined as the ratio between the available generation capacity and the maximum average hourly demand.

The TSO estimates the probability distribution function of the available power in the generation facilities with a convolution of the probability distribution function from each technology. With this probability distribution function it estimates the probability to meet the expected peak demand in 2020 (see Figure 7). This is the first attempt of a probabilistic assessment.

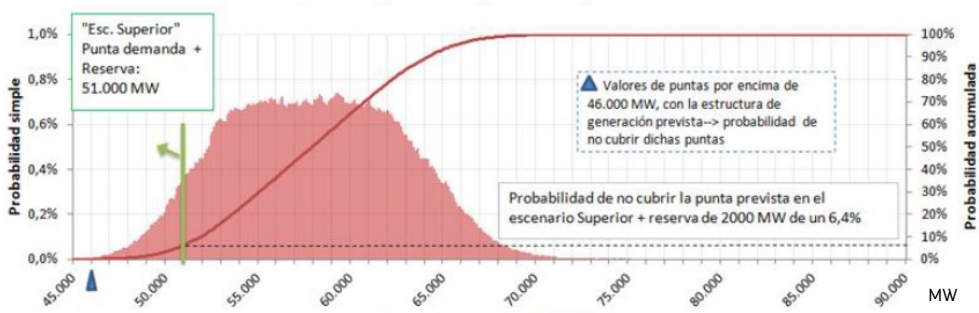



**Figure 7. [SPAIN] Available generation capacity probability function. Spanish Peninsular System. Higher scenario for winter peak demand 2020. Green vertical line: Winter peak demand plus reserves (51000 MW). Red line: cumulative probability of available generation capacity**
**Source: *Planificación de la red de Transporte de Energía Eléctrica 2015-2020.***

### Demand

Demand is estimated in several steps:

STEP 1: Three different scenarios of demand are predicted based on different GDP forecasts.

| Scenario of Demand | Author of the GDP forecast |
|---|---|
| High | Spanish Government |
| Central | Average value from different forecasters (MINETUR[a], CEPREDE[b], IMF, ConsensusForecast) |
| Low | International Monetary Fund |

[a] Ministry of Industry, Energy and Tourism. [b] Economic Forecasting Center Association.

STEP 2: Historical demand behaviour.

GDP is compared with the Maximum Instantaneous Power and the Demand at Power Station busbars (see Table 2). The same data are showed graphically in Figure 8 and Figure 9. From Figure 8 it can be seen that the variation of Maximum Instantaneous Power does not follow the same evolution as the other variables. Until 2010 demand growth was perfectly correlated with GDP. The different pattern between energy and instantaneous power can be seen also in Figure 9.

| | **GDP** | **Maximum Instantaneous Power** | | **Demand at Power Station busbars** | | |
|---|---|---|---|---|---|---|
| | % | MW | % (*) | TWh | % (*) | corrected % (**) |
| 2006 | 4.1 | 42 430 | -2.9 | 255.0 | 3.1 | 4.2 |
| 2007 | 3.5 | 45 450 | 7.1 | 262.4 | 2.9 | 4.2 |
| 2008 | 0.9 | 43 252 | -4.8 | 265.2 | 1.1 | 0.7 |
| 2009 | -3.8 | 44 496 | 2.9 | 252.7 | -4.7 | -4.9 |
| 2010 | -0.2 | 44 486 | 0.0 | 260.5 | 3.1 | 2.9 |
| 2011 | 0.1 | 43 969 | -1.2 | 255.6 | -1.9 | -1.0 |
| 2012 | -1.6 | 43 527 | -1.0 | 252.1 | -1.4 | -2.0 |
| 2013 | -1.2 | 40 277 | -7.5 | 246.3 | -2.3 | -2.2 |

(*) Percentage change over previous year.

(**) Corrected by temperature and working pattern effect. Average daily temperatures below 15 °C in winter and above 20 °C in summer produce an increase in demand. Working pattern is the number of working days of the year.

**Table 2. [SPAIN] Comparison between GDP, Maximum Power and Demand at Power Station busbars. Spanish Peninsular System.**
**Source: Planificación de la red de Transporte de Energía Eléctrica 2015-2020.**

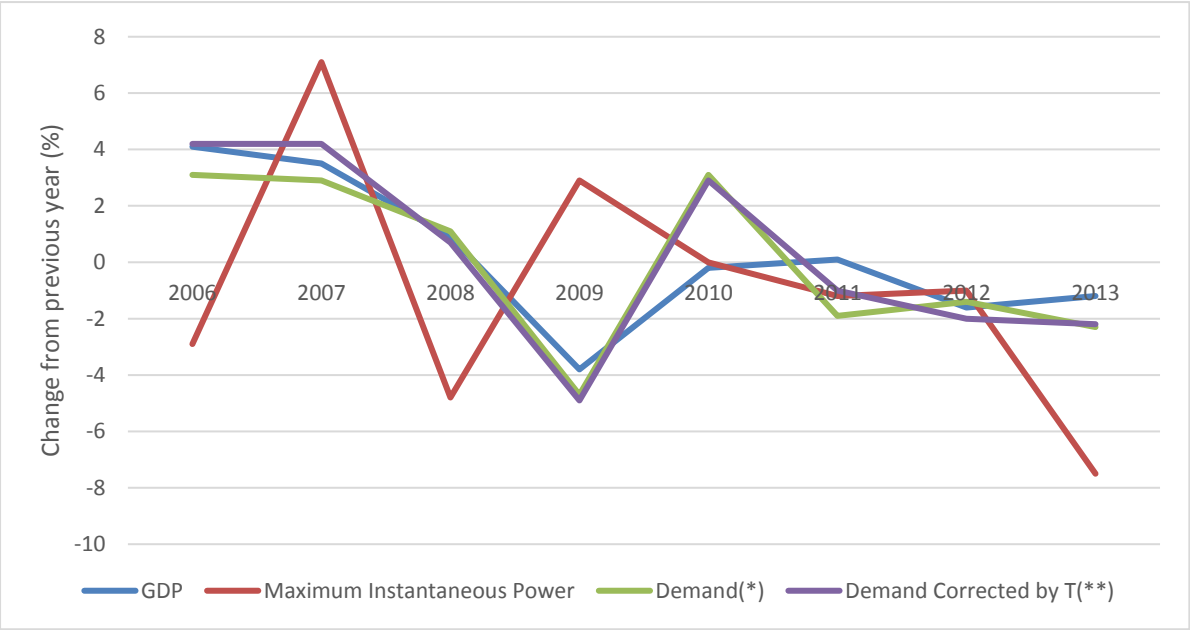



**Figure 8. [SPAIN] Rate of annual change of GDP, Maximum Instantaneous Power, Demand and Demand corrected by temperature.**

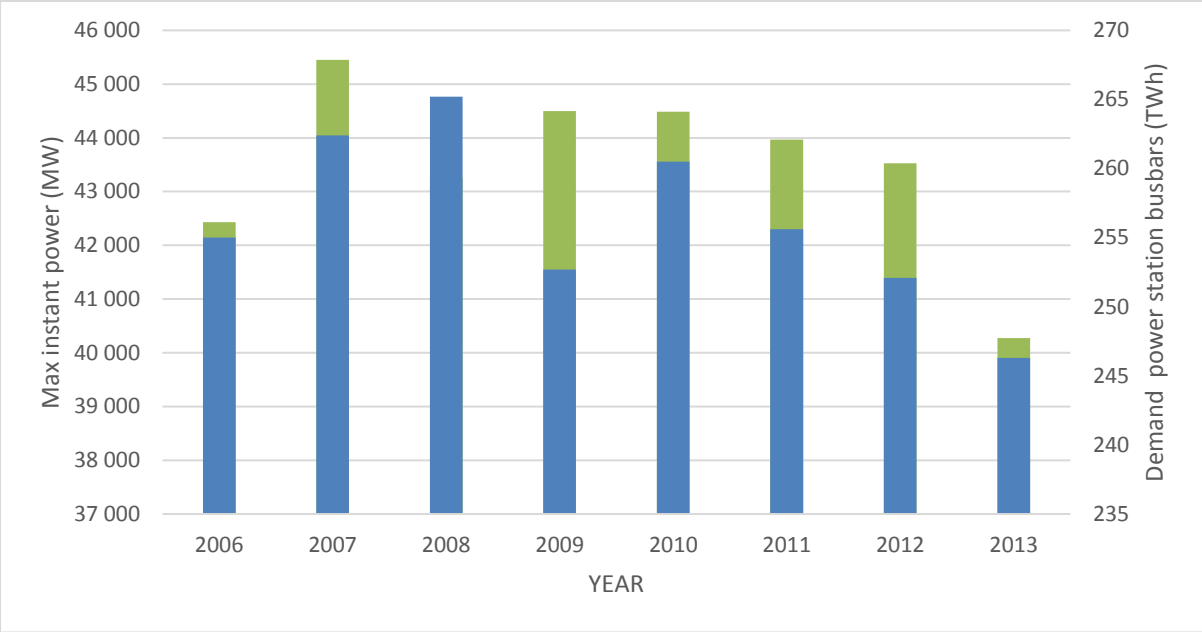



**Figure 9. [SPAIN] Evolution of maximum instantaneous and demand in MW and TWh respectively.**

Secondly, the TSO had analysed the evolution of the electricity intensity (electricity consumption per unit of GDP) considering also the electrification level of the economy. In this regard, there is a continuous electrification of the economy, with a transfer of energy consumption from natural gas and petroleum to electricity. Electricity intensity grew an average value of 1.5 % from 2000 to 2005, and it remained stable from 2006 to 2013. Projections for 2015-2020 indicate a yearly decrease of 0.5 %.

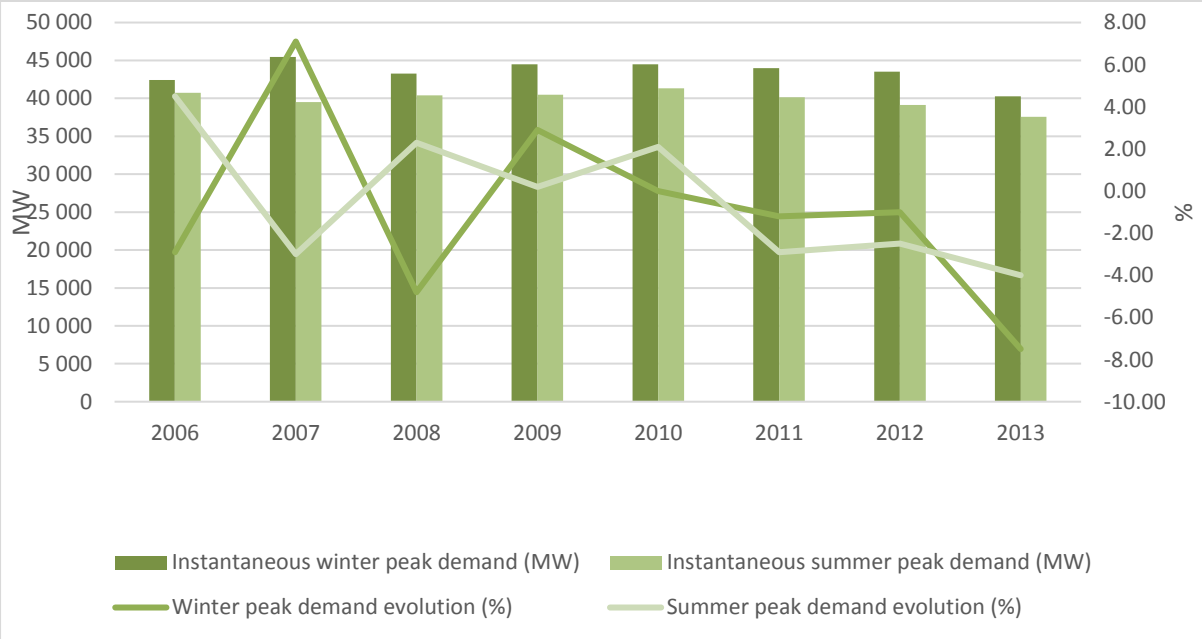



**Figure 10. [SPAIN] Winter and Summer instantaneous peak demand. Spanish Peninsular System. Source: *Planificación de la red de Transporte de Energía Eléctrica 2015-2020*.**

Figure 10 shows the evolution of the peak demand over the years. The maximum instantaneous peak demand was 45450 MW (year 2007) coinciding with a cold spell. Maximum average hourly power demand was, at that moment, 44904 MW. The evolution of winter and summer peak demand does not follow the same pattern as it is driven by temperature.

STEP 3: Demand forecast

The maximum average hourly power demand is estimated with respect to three different scenarios (higher, central and lower), each of them built on the following elements:

- Three different assumptions on the GDP evolution.
- Assumptions regarding the electrical intensity:
  - For the higher and central scenario, a yearly reduction of 0.4 % for the period 2014-2020.
  - For the lower scenario, the TSO, based on econometric models, did a lower prevision of the reduction of the electrical intensity (but does not publish the estimation).
- Peak demand forecasts:
  - Heating and cooling demand is based on cold temperatures in winter and hot temperatures in summer. There is no weather normalisation. Demand is estimated based on weather conditions which happen at least once every 10 years.
  - Working pattern effect is considered.
  - For each scenario, the TSO assume different demand side management levels and different penetration of the electrical vehicles.
  - It also considers the 2nd Spanish energy efficiency action plan 2011-2020.

With the estimation of the energy demand (see Table 3), the TSO makes an estimation of the maximum average hourly power demand for winter and summer in the three scenarios (see Figure 11). The mathematical procedure on how it is done is not explained.

| Year | Peninsular electrical energy demand (TWh) | | |
|---|---|---|---|
| | Lower | Central | Higher |
| 2012 (real) | 252.1 | 252.1 | 252.1 |
| 2013 (real) | 246.3 | 246.3 | 246.3 |
| 2015 (forecast) | 249.3 | 251.6 | 251.7 |
| 2020 (forecast) | 273.1 | 277.7 | 284.9 |

**Table 3. [SPAIN] Evolution of the annual energy demand. Spanish peninsular electrical system.**
**Source: *Planificación de la red de Transporte de Energía Eléctrica 2015-2020*.**

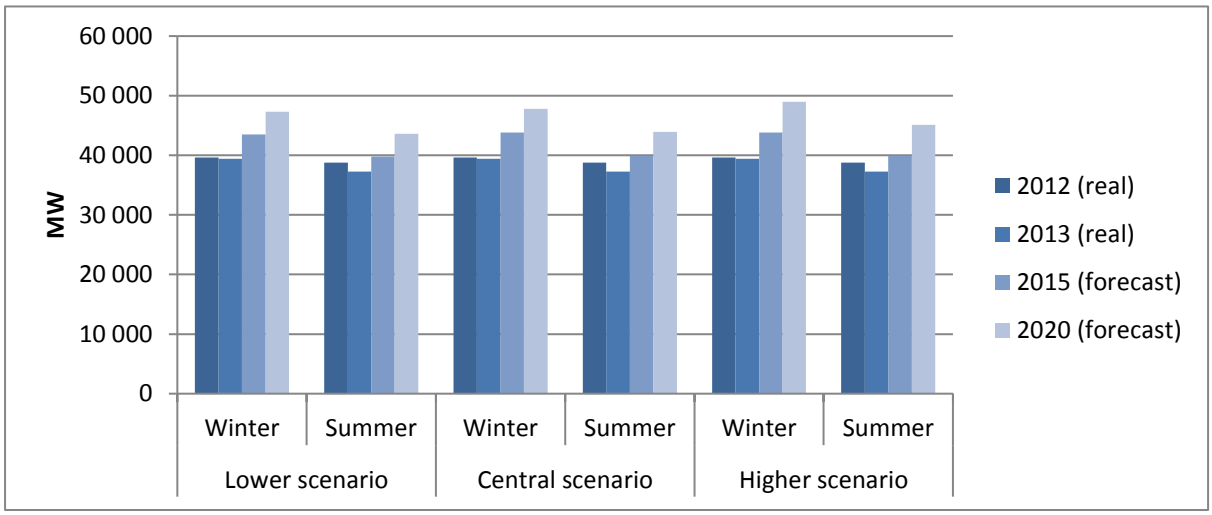



**Figure 11. [SPAIN] Peak demand forecasting. Spanish Peninsular System.**
**Source: *Planificacion de la red de Transporte de Energia Electrica 2015-2020*.**

## Supply

Projections for the installed capacity up to 2020 are presented in Figure 12. They consider the decommissioning of some coal power plants due to the Industrial Emissions Directive (Directive 2010/75/EU), the decommissioning of the only fuel power plant as it will reach its useful time. The evolution of the renewable generation capacity is based on the previsions from the Secretary of Energy and regarding CCGT power plants there is a high uncertainty as several generation units have requested a mothballed period.

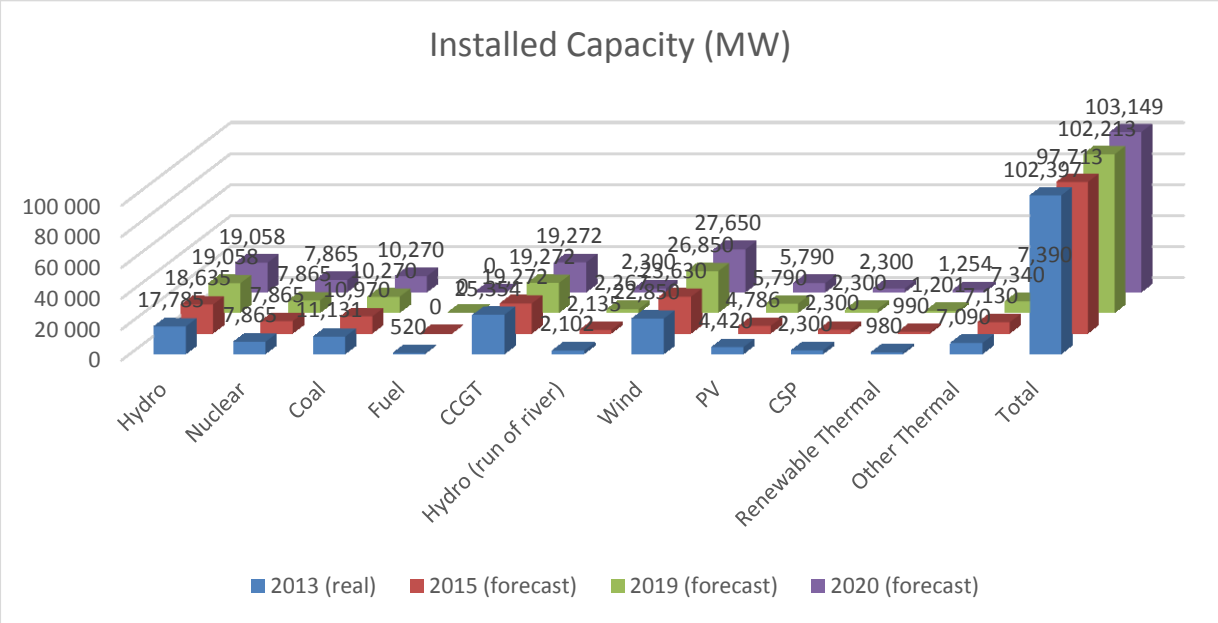



**Figure 12. [SPAIN] Evolution of the generation mix. Spanish peninsular system.**
**Source: *Planificación de la red de Transporte de Energía Eléctrica 2015-2020. Consultation report.***

### Availability of the different generation technologies

For the estimation of the available power in the system, Pd, the TSO does not provide either explicit figures or the methodology for its calculation but it is said that:

- Wind energy contributes to the winter peak demand only with an average value of 9 % of their installed capacity.
- PV does not contribute to the winter peak demand (peak demand takes place at 21:00).
- Hydro is very variable, depending on the year. In an average year, less than half of the installed capacity is ensured as available power.
- For the other technologies, the available capacity depends on the self-supply, maintenance and failure rates.

## Scenarios

There are three different scenarios based on the three scenarios for demand and one scenario for generation.

## Consideration of reserves.

They are not considered explicitly. They are considered into the 1.1 target value for the Coverage index. It is said that the TSO needs 2000 MW as reserves to operate the system securely.

## Interconnectors

International exchanges are not considered in the assessment.

## Indicators

Adequacy is measured with the following power balance:

$$IC = Pd/Ps \qquad \text{Eq. 1}$$

where IC is the coverage index, Pd the available generation power in the system and Ps is the peak level of power demanded from the system. Target value for the Coverage index >=1.1.

The index is estimated in winter and summer peak demand hours.

## Results

A power balance for the winter and summer peak demand hours is done with the following hypothesis:

- It is supposed that it is a dry hydrological season.
- 6000 MW of combined cycles will be mothballed.
- No international exchanges.
- Although there are already 2000 MW of demand with interruptibility service (interruptibility is a mechanism whereby certain large consumers pay lower prices in return for a willingness to interrupt their demand if the operator so requests), it is not considered in the analysis.

Results for the winter analysis are shown in Table 4 and Figure 13.

| | 2013 | 2019 (F) | 2020 (F) |
|---|---|---|---|
| Installed capacity (MW) | 102 397 | 102 214 | 103 150 |
| Available capacity (MW) | 56 420 | 51 710 | 51 860 |
| **Higher scenario** | | | |
| Winter peak demand (MW) | 39 411 | 47 900 | 49 000 |
| Coverage index (IC) | 1.43 | 1.08 | 1.06 |
| Difference with the target (IC=1.1) in MW | 13 068 | -1 030 | -2 170 |
| **Central scenario** | | | |
| Winter peak demand (MW) | 39 411 | 47 000 | 47 800 |
| Coverage index (IC) | 1.43 | 1.10 | 1.08 |
| Difference with the target (IC=1.1) in MW | 13 068 | 10 | -760 |
| **Lower scenario** | | | |
| Winter peak demand (MW) | 39 411 | 46 300 | 47 300 |
| Coverage index (IC) | 1.43 | 1.12 | 1.096 |
| Difference with the target (IC=1.1) in MW | 13 068 | 780 | -180 |

**Table 4. [SPAIN] Power balance for the Spanish Peninsular System. Winter peak demand. Higher, central and lower scenarios.**
**Source: *Planificacion de la red de Transporte de Energia Electrica 2015-2020.***

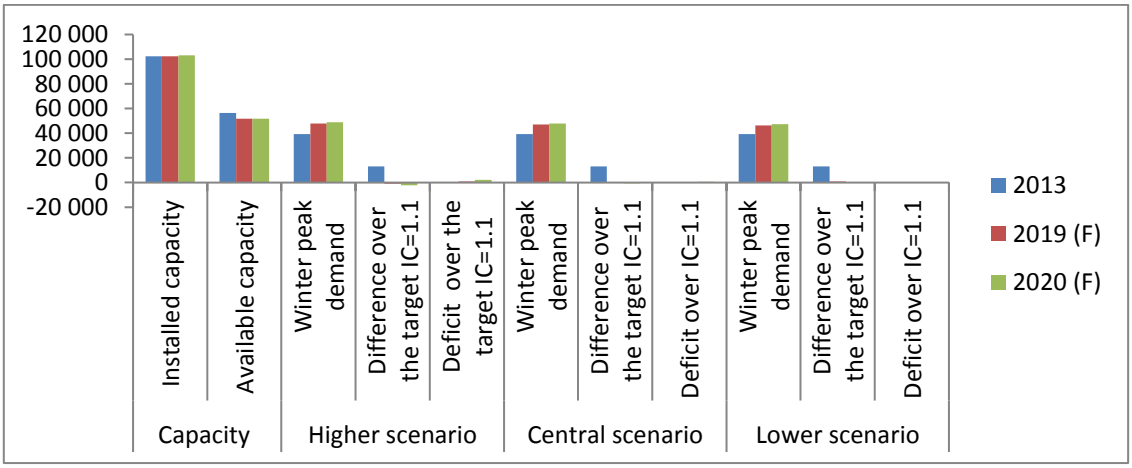



**Figure 13. [SPAIN] Evolution of the power balance for Spanish Peninsular System at winter peak time. Results for higher, central and lower scenarios.**

The results for the summer peak demand hour in the higher scenario are displayed in Table 5. At summer time the system is always above the target.

| | 2013 | 2019 (F) | 2020 (F) |
|---|---|---|---|
| Available capacity (MW) | 53 400 | 52 420 | 52 540 |
| Summer peak demand (MW) | 37 247 | 44 000 | 45 100 |
| Coverage index (IC) | 1.43 | 1.19 | 1.16 |
| Difference with the target (IC=1.1) in MW | 12 428 | 4 020 | 2 930 |

**Table 5. [SPAIN] Power balance for the Spanish Peninsular System. Summer peak demand in the higher scenario.**
**Source: *Planificacion de la red de Transporte de Energia Electrica 2015-2020.***

Finally an annual energy balance is estimated with real data for 2013 and with forecasted data for 2015 and 2020 with the following hypothesis:

- It is supposed that it is an average hydrological season.
- It is supposed that there is average wind energy generation.
- It is supposed that 2170 mothballed MW will be in service again in 2020.
- Curtailment is not considered although the TSO expects an increase of it.

It is worth noting that 2013 was a dry year with high winds, too. The results are shown in Figure 14 and Table 6.

| **Balance (GWh)** | **2013** | **2015 (F)** | **2020 (F)** |
|---|---|---|---|
| Hydro | 33 970 | 29 680 | 30 220 |
| Nuclear | 56 827 | 56 140 | 59 670 |
| Coal | 39 807 | 45 030 | 44 690 |
| Fuel Gas | 0 | 0 | 0 |
| Combined cycles | 25 091 | 32 030 | 49 790 |
| Total Ordinary Regime | 155 695 | 162 880 | 184 370 |
| RES Hydro | 7 099 | 6 140 | 6 620 |
| Wind | 54 338 | 54 410 | 61 310 |
| PV | 7 915 | 8 140 | 9 840 |
| CSP | 4 442 | 6 560 | 6 560 |
| Thermal RES | 5 064 | 5 890 | 7 310 |
| Cogeneration + non-RES Thermal | 31 989 | 34 010 | 35 350 |
| Total special regimen | 110 847 | 115 150 | 126 990 |
| Total generation | 266 542 | 278 030 | 311 360 |
| Self-consumption (OR) | -6 270 | -7 540 | -7 920 |
| Hydro Pumped consumption | -5 958 | -5 260 | -6 020 |
| International exchanges (Balearic islands included) | -8 001 | -11 500 | -12 500 |
| Demand at power station busbars (GWh) | 246 313 | 253 730 | 284 920 |

**Table 6. [SPAIN] Energy balance for the Spanish Peninsular system. Higher scenario.**
**Source: *Planificación de la red de Transporte de Energía Eléctrica 2015-2020.***

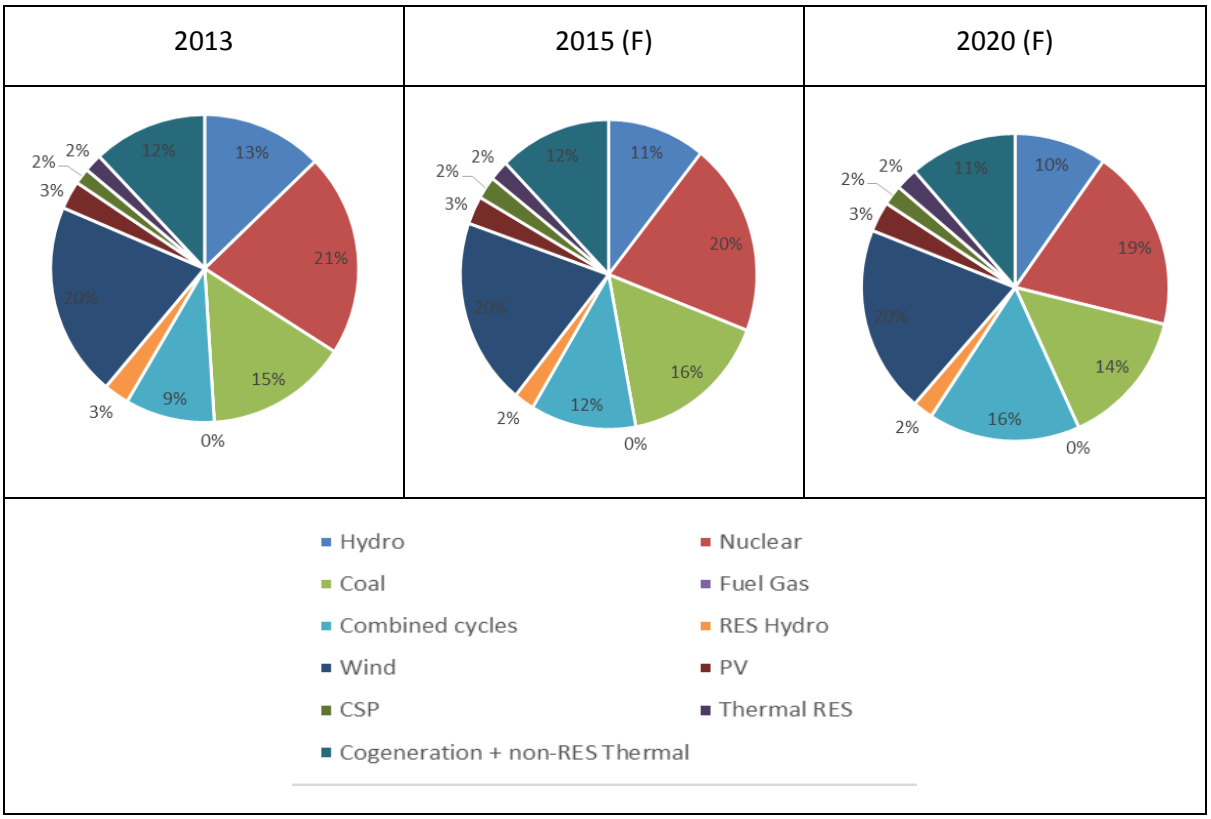



**Figure 14. [SPAIN] Energy balance evolution.**

### Remarks

Spain is still assessing adequacy with a deterministic power balance. Only one indicator is estimated and there is a lack of information about some estimations (for example, how availabilities are calculated). Power balances are estimated using dry hydrological seasons although the results presented for the annual energy balance assume average hydrological seasons which produces an inconsistent analysis.

International exchanges and the existing interruptibility service provided by 2000 MW of demand are not considered in the assessment which leads to a pessimistic evolution of the system.

Finally, there is no estimation of flexibility needs. In this regard, in the report it is mentioned that curtailment is not considered although the TSO expects an increase of it.

## 2.3 Portugal

Decree-Law 29/2006 establishes that the State guarantees the security of supply, and the Directorate General of Energy and Geology (DGEG) with the cooperation of the concessionary of the national transmission network (REN) will periodically draw up a monitoring report to assess security of supply. The report should be published every second year. In the intermediate years, a simple assessment shall be performed. The report should be presented to the Government, the Assembly of the Republic and the European Commission The last report we found on the internet was published in 2013: *Relatório de Monitorização da Segurança de Abastecimento do Sistema Elétrico Nacional*, [15], and it covers the time period between 2013 and 2030, although there should be a more updated one.

### Methodology

A sequential Monte Carlo probabilistic assessment is performed. Two models are used:

- VALORAGUA: MIBEL market model simulator. It assumes perfect competition. MIBEL is the Iberian Electricity Market.

- RESERVAs: Probabilistic assessment of security of supply. Sequential Monte Carlo simulations with hourly resolution and with a detailed representation of wind resources.

## Demand

Table 7 presents the main assumptions considered in the demand model and Figure 15 shows the evolution of the expected demand. It is foreseen considering two scenarios. Each of them considers measurements from the NEEAP (National Energy Efficiency Action Plan) extended until 2030 and different levels of electric vehicles penetration.

- Central or baseline scenario: demand increases 1.14 % yearly in the period 2012-2030.
- Higher scenario: demand increases 1.45 % yearly in the period 2012-2030.

| **GDP** | **2012-2015** | **2015-2020** | **2020-2030** |
|---|---|---|---|
| Annual Average Growth Rate | 0.6 % [a] | 2 % [a] | 2 % [b] |
| | | | |
| **Brent** | **2012-2020** | | **2015-2030** |
| Price | 107 $USD_{2012}$/bbl [c] | | 98 $USD_{2015}$/bbl [d] |
| Annual Average Growth Rate | -2.9 % [c] | | + 1.4 % [d] |
| **CO2** | **2012-2020** | | **2020-2030** |
| Price | 9.0 $EUR_{2011}$/tonne $CO_2$ [e] | | 15.0 $EUR_{2011}$/tonne $CO_2$ [f] |
| Annual Average Growth Rate | 18.6 % [e] | | 4.5 % [f] |

a. Source: Finance Ministry. These values are the same that were used for the NREP (National Renewable Energy Plan) and the NEEAP (National Energy Efficiency Action Plan).
b Based on the study 'Macroeconomic Scenarios for the Portuguese Economy 2006-2030' of May 2006 elaborated by the Ministry of Economy and Innovation for REN.
c. Ministry of Finance.
d. International Energy Agency. World Energy Outlook 2011 (WEO2011) Scenario 'New Policies'.
e. Average value from different forecasts: Barclays PLC, Commerzbank AG and Societe General SA.
f. IEA WEO2011. Scenario 'Current Policies — European Union'.
g. The three of them consider measurements from the NEEAP, extended until 2030 and different levels of electric vehicles penetration.

**Table 7. [PORTUGAL] Assumptions of demand model.**

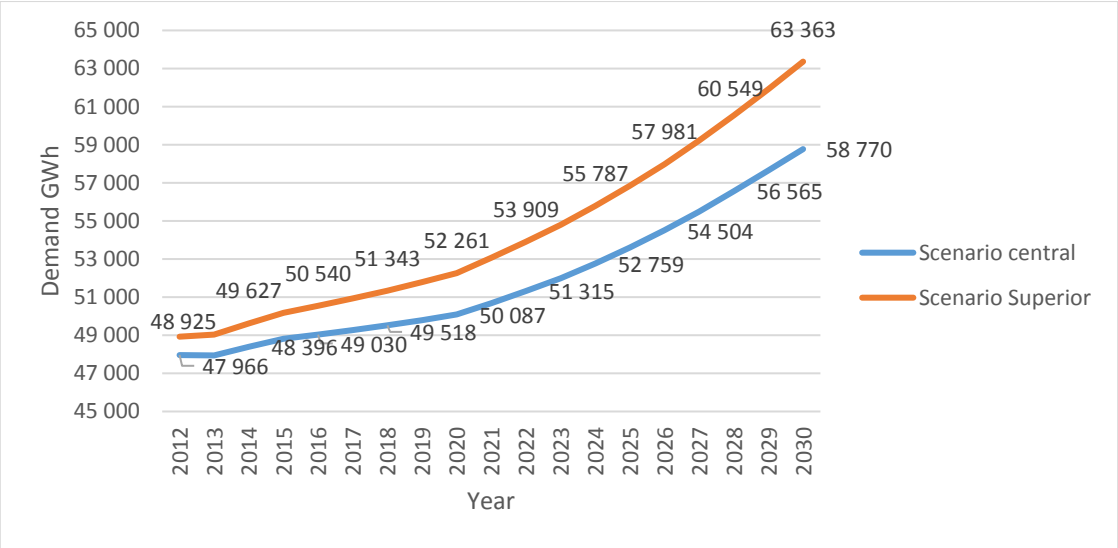



**Figure 15. [PORTUGAL] Evolution of demand.**
**Source:** ***Relatório de Monitorização da Segurança de Abastecimento do Sistema Elétrico Nacional 2013-2030.***

## Supply

For the model of supply two different scenarios are considered. The central scenario is estimated considering the expected evolution of the generation mix with the following assumptions:

a. Thermal: 5 generators will be decommissioned with a capacity of 3857 MW and 2 new CCGT generators will be commissioned in 2017 with an installed capacity of 1766 MW.

b. Hydro: it follows the National Plan of Dams and the expected date of Commissioning from DGEG. 4635 MW of new hydro power plants are forseen, of which 4016 will be pumping stations.

c. RES: it is predicted that the NREP will be followed until 2020 and then, between 2020 and 2030 a conservative estimation of the new capacity is considered. The dominant renewable technology will be wind, with 6400 MW in 2030, follow by PV with 640.

d. CHP plants will reach 2250 MW in 2030.

A 'break-down' scenario is considered assuming that there will not be new installed capacity.

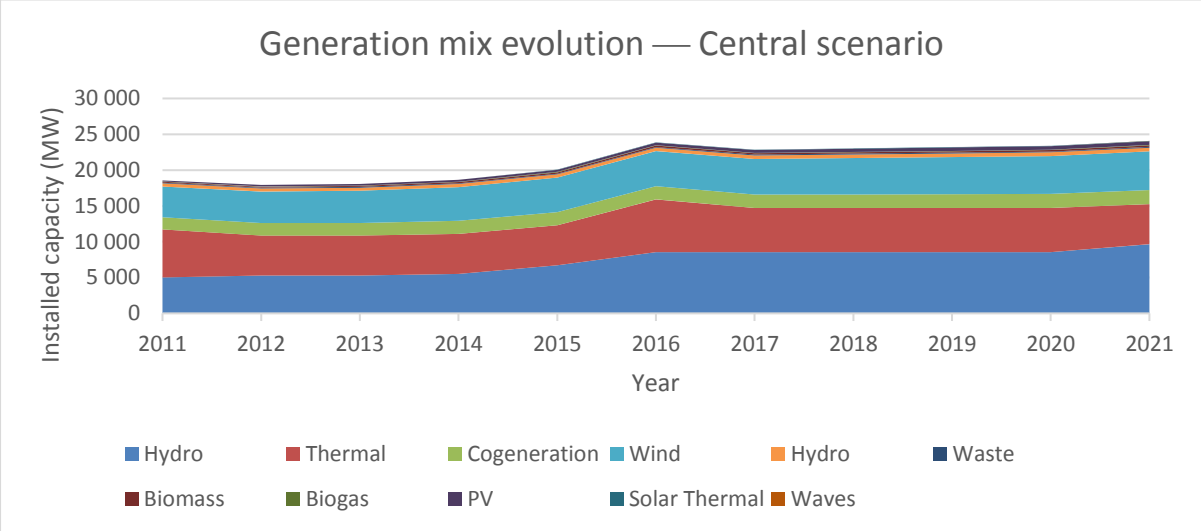



**Figure 16. [PORTUGAL] Evolution of the generation mix. Central scenario.**

The model has a detailed representation of wind resources, by dividing the territory into several regions with different wind behaviours, each with its own set of historical wind series.

Hydro generation systems are simulated considering 40 years of historical data, from 1966 to 2005. Wet reference conditions are estimated with an average value of years 1966, 1978 and 1979 (with a 5 % probability of being exceeded) and dry reference conditions are estimated with an average value of years 1981, 1992 and 2005 (with a 92 % probability of being exceeded).

| | **Baseline** | **Sensitivity** | **Break down** |
|---|---|---|---|
| **Demand** | Central | Superior | Superior |
| **Supply** | Baseline | Baseline | Break down (as it is now) |
| **Objective** | Assess normal conditions | Assess high demand scenario | Estimate the year in which the generation fleet cannot guarantee adequate levels for security of supply without new installed capacity |

**Table 8. [PORTUGAL] Planning scenarios for the assessment.**

## Scenarios

With the two scenarios for demand and generation, three different combinations are performed as it is shown in Table 8. Table 9 presents the main hypothesis for each scenario.

| **Scenario** | **Baseline** | **Sensitivity** | **Break down** |
|---|---|---|---|
| Demand | 58.8 $TWh_{2030}$ | 63.4 $TWh_{2030}$ | 63.4 $TWh_{2030}$ |
| $AAGR_{2012-2030}$ | 1.14 % | 1.45 % | 1.45 % |
| New Generation Capacity (GW) | | | |
| Thermal | 1.7 | 1.7 | 0 |
| Hydro | 4.6 [a] | 4.6 [a] | 2.4 [b] |
| RES | 3.4 | 3.4 | 0.5 |
| Wind | 2 | 2 | 0.3 |
| Solar | 0.5 | 0.5 | 0.1 |
| Hydro | 0.2 | 0.2 | 0.02 |
| Cogeneration | 0.6 | 0.6 | 0.06 |
| Other | 0.1 | 0.1 | 0.02 |
| Total new generation capacity (GW) | 13.1 | 13.1 | 3.4 |

[a] 4 GW reversible turbine-pump. [b] 2 GW reversible turbine-pump.

**Table 9. [PORTUGAL] Main hypothesis for each scenario.**

## Consideration of reserves

The software tool RESERVAS estimates, for each hour, if the system will have enough operational reserve. The main advantage of this approach is that it can capture what will happen in between 2 hours, something that is not captured with the Monte Carlo simulation as the market tool does not simulate balancing markets. So, with RESERVAS, sub-hourly possible constraints are assessed.

The operational reserve is built by considering three elements: unexpected wind generation variations, unexpected changes in demand and the changes in the available capacity due to unavailability. For each hour t, if the available reserve capacity is shorter than the sum of these three elements, the system is considered not adequate for supplying demand for this hour.

The estimation of the operational reserve needs is performed considering secondary and tertiary reserves. So, the estimation of flexibility needs is considered through the analysis of the reserve needs.

## Interconnections

Simulations were performed considering an isolated system, Net Transfer Capacity (NTC) to be zero until 2014 and from 2015 with a NTC of 10%. Expected future interconnection capacity between Spain and Portugal are showed in Table 10. VALORAGUA (market simulator) uses these values with a reduction of 20%.

| | Year | 2012 | 2014 | 2017 | 2020 | 2025 |
|---|---|---|---|---|---|---|
| Portugal→Spain | Summer | 1 700 | 2 800 | 3 000 | 3 200 | 3 200 |
| | Winter | 1 700 | 2 800 | 3 000 | 3 200 | 3 200 |
| Spain→Portugal | Summer | 2 000 | 2 200 | 3 000 | 3 200 | 3 200 |
| | Winter | 1 600 | 2 200 | 3 000 | 3 200 | 3 200 |

**Table 10. [PORTUGAL] NTC of interconnection between Portugal and Spain.**

## Indicators

The software (RESERVAS) assesses the indicators (LOLP, LOLE, EPNS, EENS, LOLF, and LOLD) in the classical way, with monthly and annual resolution. The probability distribution function of the indicators is also provided, which enables estimation of the risk associated to them. Also, the tool estimates the coverage index of the peak demand in a probabilistic way (with the probability distribution function) with the following information:

- ICPA: Coverage index of the annual peak demand.
- ICPM: Coverage index of the monthly peak demand.
- ICMIN: minimum monthly coverage index.

For the adequacy assessment the two main indicators are:

- Probabilistic coverage index of the annual peak demand (ICP).
- LOLE.

LOLE is composed of two elements: static LOLE which is the loss of demand due to lack of generation capacity and the loss of demand due to inadequate operational reserve.

With the following target values:

- ICP shall be ≥ 1.0 with a probability of occurrence between 95 % and 99 %.
- LOLE ≤ 8 hours.

Also curtailment is estimated with and without the new pumping hydro facilities to highlight the importance of pumping hydro systems as a balancing tool in periods with high renewable generation (see Figure 18). The assessment considers the 40 annual hydrological time series.

## Results

The probabilistic coverage index is shown in Figure 17. Its value is always higher than 1 except 2023 and subsequent years in the break-down scenario (whose purpose is to see when the system will have adequacy problems if no new generation capacity will be installed).

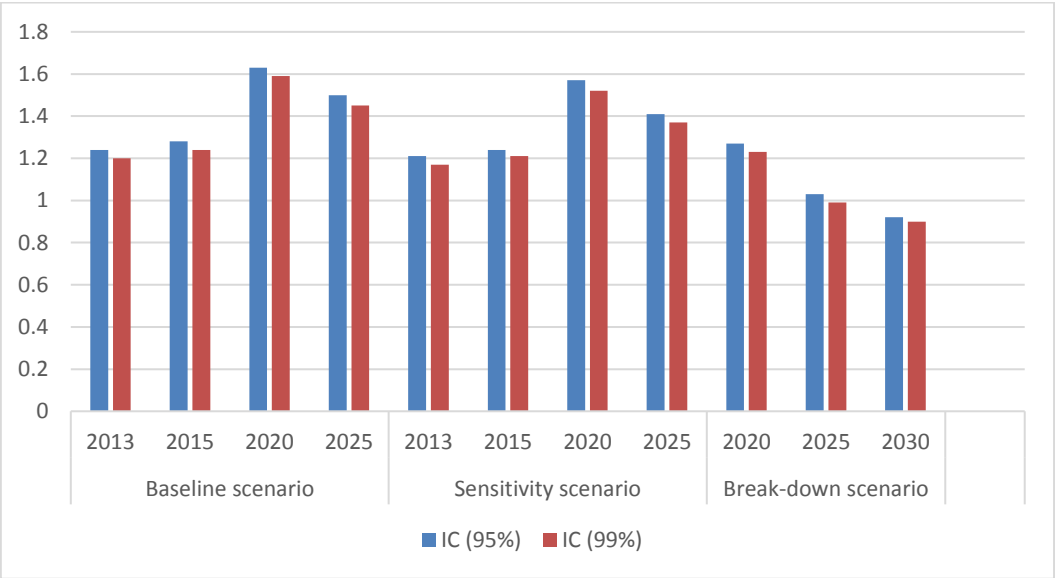



**Figure 17. [PORTUGAL] Probabilistic Coverage Index for the baseline, sensitivity and break-down scenario.**

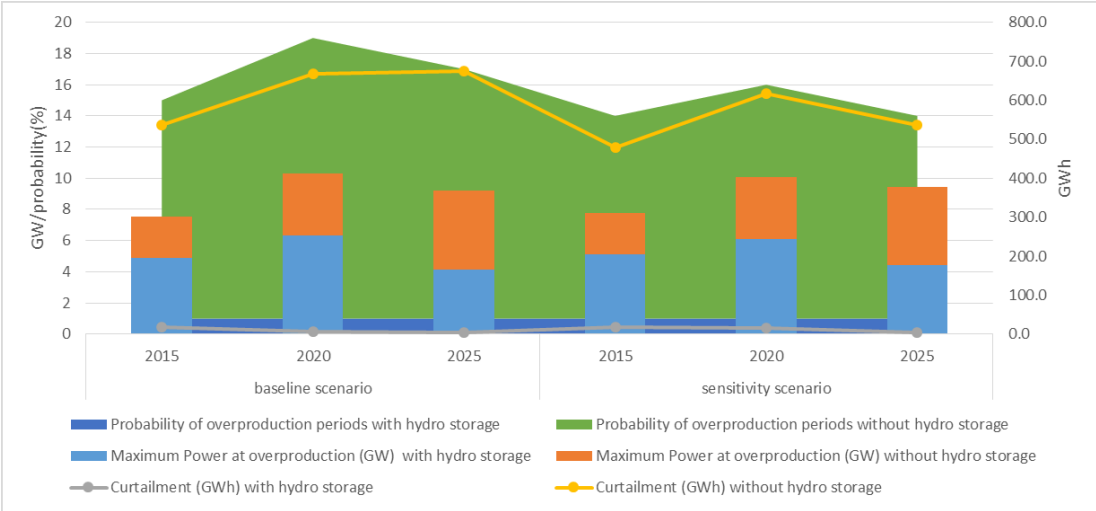
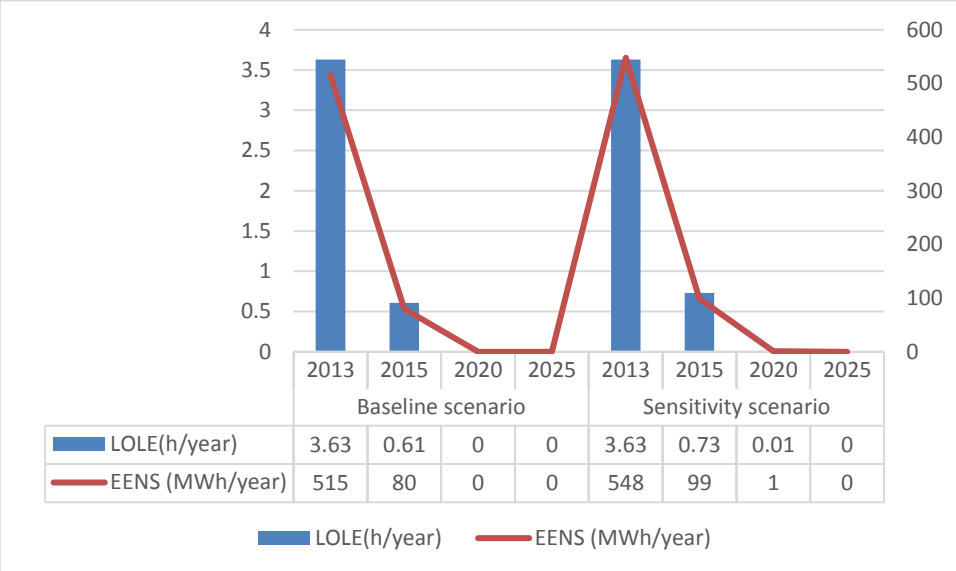



**Figure 18. [PORTUGAL] Estimation of periods with overgeneration. Role of pumping power stations in the reduction of curtailment.**

Finally, Figure 19 shows the results in terms of LOLE and ENNS in the baseline and sensitivity scenarios. It is worth mentioning that LOLE is made by two terms: one due to adequacy and the other due to operational constraints.




| | 2013 | 2015 | 2020 | 2025 | 2013 | 2015 | 2020 | 2025 |
|---|---|---|---|---|---|---|---|---|
| LOLE(h/year) | 3.63 | 0.61 | 0 | 0 | 3.63 | 0.73 | 0.01 | 0 |
| EENS (MWh/year) | 515 | 80 | 0 | 0 | 548 | 99 | 1 | 0 |

**Figure 19. [PORTUGAL] LOLE and EENS. Baseline and sensitivity scenarios.**

## Remarks

Portugal uses a sequential Monte Carlo simulation to assess adequacy, considering storage and the interconnection capacity with Spain. The model also contains the assessment of flexibility issues as it estimates the reserve needs. The report presents more details than what is presented here, with an estimation of curtailment, thermal generators working hours in different hydro conditions, estimation of $CO_2$ emissions, energy balances, etc. Although it seems that a new report should be available, this study was done analysing the report from 2013.

## 2.4 The Netherlands

The transmission system operator of the Netherlands, TenneT, performs the generation adequacy assessment every year. The last report, 'Security of Supply monitoring Report 2014-2030' ( [16]), was published in July 2015. The purpose of monitoring is to provide an insight into the expected development of the domestic supply and demand for electricity over a period of 7 years. As EU Directive 2005/89/EC establishes that Member States shall forecast the security of supply level for the period between 5 and 15 years from the date of the report, it also includes a look ahead until 2029.

The monitoring activities and the requested data collection are carried out pursuant to Electricity Act, Section 16, Subsection 2f, which assigns to TenneT the task of monitoring the security of delivery and supply at the request of the Minister of Economic Affairs.

### Methodology

National security of supply monitoring is based on the assessment of LOLE although no details about the model are provided. The existing methodology will be used in parallel with the regional PLEF assessment in the coming years although the expectation if that the regioanl model will play an increasingly important role as it is an improved estimate of the impact of renewable generation and to what extent the different market areas within the region can support each other in times of scarcity.

As in many other cases, the assessment does not cover extreme situations which may occur due to cooling water restrictions in summer due to a heat wave, or due to the unavailability of sufficient primary fuels (coal and natural gas).

### Demand

Two different scenarios for demand are estimated. Demand is forecasted with lower values than the estimations performed in previous assessments. From 2015 the demand is estimated considering the evolution by sector, and not only taking into account GDP evolution, which has led to the insight that the future demand will rise more slowly than the projected demand considered in the previous reports. Demand is calculated annnually up to 2022 and for 2030. The values from 2022 to 2030 are estimated by interpolation.

The reference scenario is estimated considering a recovery of demand from industry, a drop in the consumption from the residential and tertiary sectors due to energy efficiency and savings and the emergence of electric vehicles and heat pumps. In total, all of these elements produce an average annual increase in electricity consumption of 0.3 % from 2013 to 2030.

In the high scenario, 2.5 million electric cars and 1.7 million heat pumps are considered in 2030 (800000 and 600000 respectively in the reference scenario). In this scenario the electricy consumption evolves with an annual growth rate of 1.5%.

### Supply

Apart from a 0.1 GW waste-fired power plant, TenneT does not expect other new thermal installed capacity. As a result of the Energy Agreement of September 2013, a phase-out of the least technically efficient coal-fired units (2.66 GW) will be accomplished.

In addition, there are plans to add 1.0 GW of new thermal generation capacity in the period up to 2021, including 0.3 GW in small-scale projects. Investments in new generation capacity may be related to the replacement of obsolete production units, reorganisation into production units with a smaller capacity, or concentration of combined-heat-and-power (CHP) capacity in clusters of companies in the horticulture sector.

Furthermore, electricity producers intend to 'mothball' 0.7 GW of capacity, and to decommission approximately 0.6 GW in the period from 2014 up to and including 2020.

An additional 2.9 GW has been earmarked for mothballing after 2020.

Solar PV generation is expected to grow from 739 MW in 2013 to 6500 MW in 2022 in accordance with the established policy scenarios from the National Energy Outlook 2014.

New installed capacity of onshore wind farms was 280 MW in 2013, making a total of 2485 MW of total installed capacity. In March 2014 the Government adopted a target of 6000 MW of new onshore wind capacity in 2020.

Regarding offshore wind capacity, since 2009 no expansion of wind power occurred in the North Sea, maintaining the total installed capacity equal to 228 MW. 129 MW are expected to be commissioned by the end of 2015 and 600 MW more at the end of 2017. Identical to the onshore target, the Government has approved a target of 6 GW in 2030 for the Dutch Coast and the North of the islands.

## Scenarios

The monitoring analysis is surrounded by a number of uncertainties. To reduce the impact of uncertainties on the results, a number of alternative assumptions are considered to build a set of different scenarios additionally to the baseline scenario as can be seen in Table 11.

| SCENARIO | ASSUMPTIONS |
|---|---|
| **BASIC** | • In the basic variant they assume a direct link between the expected increase in electricity consumption and the economic growth forecast published by the Netherlands Bureau for Economic Policy Analysis (CPB).<br>• Availability of generation units is based on the information provided by producers. |
| **Variant A** | • Unavailability figures of generating units are based on the historical average. |
| **Variant B** | • Reduced realisation of new production capacity and with the assumption that current projects will actually be realised.<br>• The unavailability of production assets is derived from historical data, same as in sensitivity variant A. |
| **Variant C** | • Same as Variant B with PV and wind available capacity = 0 and 10 % respectively. |
| **Variant D** | • Scenario A with higher demand. |

**Table 11. [THE NETHERLANDS] Scenario assumptions.**

## Consideration of reserves

It is not mentioned if reserves are considered in the assessment. A reserve factor is estimated as a ratio between the maximum available capacity and the peak demand. Three different cases are analysed:

- Case 1: total operational capacity is considered as 100 % but without considering imports.
- Case 2: capacity value of renewable energy is estimated as 20 % but again, without considering imports.
- Case 3: renewable energy capacity value is estimated as 20 % of its nominal value but available interconnection capacity is also considered.

In Table 12 it can be seen that the reserve factor is always higher than 1.

| Year | Non-op. capacity | Operational capacity | | Available interconnection capacity | Peak demand | Reserve factor | | |
|---|---|---|---|---|---|---|---|---|
| | | Total | RES | | | Case 1 | Case 2 | Case 3 |
| 2014 | 2.7 | 28.7 | 3.5 | 5.5 | 17.9 | 1.60 | 1.45 | 1.75 |
| 2015 | 4.3 | 29.0 | 4.2 | 5.5 | 18.0 | 1.61 | 1.42 | 1.73 |
| 2016 | 4.7 | 27.5 | 5.1 | 5.5 | 18.1 | 1.52 | 1.29 | 1.60 |
| 2019 | 5.1 | 30.7 | 9.5 | 8.0 | 18.1 | 1.70 | 1.28 | 1.72 |
| 2022 | 6.2 | 35.0 | 15.1 | 8.7 | 18.3 | 1.91 | 1.25 | 1.73 |

**Table 12. [THE NETHERLANDS] Reserve factor in the baseline scenario with different assumptions on RES availabilities and import capacity.**

## Interconnectors

Interconnectors are not considered in the assessment of LOLE. In a second step, the estimated generation capacity surplus or deficit is compared with the available transmission capacity for imports and exports.

## Indicators

Security of supply is measured through the LOLE. The target value for the Dutch system is 4 hours/year. This value is estimated based on macroeconomic considerations, addressing the social damage caused by a power outage. By comparing this cost with the investment cost of additional production capacity, the desired reliability level can be determined. In the case that the result exceed this value it is an indication of how much capacity can be maximally removed (or exported) from the system. If the result is smaller than the target, it is an estimation of how much capacity is to be added (or imported) to the system to fulfill the reliability criterion.

## Results

Baseline scenario

Table 13 shows the results in the baseline scenario. Supply is divided into operational and non-operational assets. The operational capability is further broken down in thermal power (except waste), renewables (solar PV, hydro and wind power mainly) and other assets (mainly waste). It can be concluded that there is no dependence on imports; the domestic generation capacity is sufficient to satisfy the applied target of 4-hours LOLE. Unavailability of fuels is not considered. The table also presents a 'firm capacity value' in addition to the outcomes in terms of LOLE. The firm value represents a surplus or deficit in terms of production capacity with 100 % availability. Table 13 shows that the firm capital surplus shrinks during the period from 2014 to 2022, with the LOLE increases to 0.1 hours in 2022. This is mainly because the decrease in the availability of thermal generation, with a moderate increase in electricity demand. The huge increase in generating capacity from renewables (solar PV and wind) has a limited contribution by its intermittent nature.

| **Baseline scenario** | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Demand (TWh) | Non-operational supply (GW) | Operational supply | | | | LOLE (hours) | Firm capacity (GW) |
| | | | RES | Thermal (except waste) | waste | total | | |
| 2011 | 118.2 | 0 | 2.4 | 23.1 | 0.8 | 26.3 | 0 | -3.2 |
| 2012 | 115.9 | 0.5 | 2.5 | 24 | 0.8 | 27.3 | 0 | -3 |
| 2013 | 115.6 | 0.8 | 2.8 | 22.7 | 1 | 26.5 | 0 | -2.6 |
| 2014 | 112.5 | 2.7 | 3.5 | 24.1 | 1.1 | 28.7 | 0 | -4.7 |
| 2015 | 113.3 | 4.3 | 4.2 | 23.8 | 1.1 | 29.1 | 0 | -3.5 |
| 2016 | 113.4 | 4.7 | 5.1 | 21.3 | 1.1 | 27.5 | 0 | -2.5 |
| 2019 | 113.8 | 5.1 | 9.5 | 19.9 | 1.2 | 30.6 | 0 | -2.2 |
| 2022 | 114.9 | 6.2 | 15.1 | 18.7 | 1.2 | 35 | 0.1 | -1.3 |

**Table 13. [THE NETHERLANDS] Baseline scenario results. Availabilities are based on producer's estimation.**

Scenario A

An important starting point for the calculations is the assumption made regarding the unavailability of means of production as a result of failures, maintenance and revisions. TenneT requires electricity producers to provide figures of individual availabilities.

It is noteworthy that a relatively low unavailability average of 12.2 % was achieved in 2014. The estimation of unavailability is close to the historical average (14 %) for 2015.

Due to discrepancies between the unavailability figures estimated by producers and actual available production capacity, a sensitivity analysis was performed in addition to the baseline scenario. Unavailability figures are assumed to be equal to the historical average value. Results are presented in Table 14.

| Sensitivity A | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Demand (TWh) | Non-operational supply (GW) | Operational supply | | | | LOLE (hours) | Firm capacity (GW) |
| | | | RES | Thermal (except waste) | waste | total | | |
| 2011 | 118.2 | 0 | 2.4 | 23.1 | 0.8 | 26.3 | 0 | -3.2 |
| 2012 | 115.9 | 0.5 | 2.5 | 24.0 | 0.8 | 27.3 | 0 | -3.0 |
| 2013 | 115.6 | 0.8 | 2.8 | 22.7 | 1.0 | 26.5 | 0 | -2.6 |
| 2014 | 112.5 | 2.7 | 3.5 | 24.1 | 1.1 | 28.7 | 0 | -4.7 |
| 2015 | 113.3 | 4.3 | 4.2 | 23.8 | 1.1 | 29.1 | 0 | -3.9 |
| 2016 | 113.4 | 4.7 | 5.1 | 21.3 | 1.1 | 27.5 | 0.01 | -2.0 |
| 2019 | 113.8 | 5.1 | 9.5 | 19.9 | 1.2 | 30.6 | 0.09 | -1.3 |
| 2022 | 114.9 | 6.2 | 15.1 | 18.7 | 1.2 | 35.0 | 0.52 | -0.8 |

**Table 14. [THE NETHERLANDS] Scenario A results. Availabilities are based on historical average values.**

Scenario B

The sensitivity variant B is based on a smaller proportion of installed capacity by assuming that market conditions require producers to take additional shutdown of installed capacity. This is also a scenario in which gas-fired plants power shall be shut down over 30 years. Availabilities are based on scenario A (historical average value).

Results show that also in this case, with the oldest coal power generators (Energy Agreement) plus the oldest gas capacity (over 30 years) decommissioned, and the availability of the remaining capacity lower than it was forecasted, there will be no adequacy problems up to 2022 as LOLE is still lower than 4.0 hours (Table 15).

| Sensitivity B | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Demand (TWh) | Non-operational supply (GW) | Operational supply | | | | LOLE (hours) | Firm capacity (GW) |
| | | | RES | Thermal (except waste) | waste | total | | |
| 2011 | 118.2 | 0 | 2.4 | 23.1 | 0.8 | 26.3 | 0 | -3.2 |
| 2012 | 115.9 | 0.5 | 2.5 | 24 | 0.8 | 27.3 | 0 | -3.0 |
| 2013 | 115.6 | 0.8 | 2.8 | 22.7 | 1 | 26.5 | 0 | -2.6 |
| 2014 | 112.5 | 2.7 | 3.5 | 24.1 | 1.1 | 28.7 | 0 | -4.7 |
| 2015 | 113.3 | 4.3 | 4.2 | 22.8 | 1.1 | 28.1 | 0 | -3.0 |
| 2016 | 113.4 | 4.7 | 5.1 | 20.4 | 1.1 | 26.6 | 0.15 | -1.2 |
| 2019 | 113.8 | 5.1 | 9.5 | 19.1 | 1.2 | 29.8 | 0.92 | -0.6 |
| 2022 | 114.9 | 6.2 | 15.1 | 17.9 | 1.2 | 34.2 | 3.26 | -0.1 |

**Table 15. [THE NETHERLANDS] Scenario B results. Hypothesis is Scenario A and reduced thermal production capacity.**

Scenario C

It is based on Scenario B and a lower capacity value for wind (10%) and PV (0%). Results, presented in Table 16, show that LOLE exceeds the target of 4 hours in 2019 and 2022 with values of 9.05 and 68.4 hours respectively.

| Sensitivity C | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Demand (TWh) | Non-operational supply (GW) | Operational supply | | | | LOLE (hours) | Firm capacity (GW) |
| | | | RES | Thermal (except waste) | waste | total | | |
| 2011 | 118.2 | 0 | 2.4 | 23.1 | 0.8 | 26.3 | 0 | -3.2 |
| 2012 | 115.9 | 0.5 | 2.5 | 24 | 0.8 | 27.3 | 0 | -3.0 |
| 2013 | 115.6 | 0.8 | 2.8 | 22.7 | 1 | 26.5 | 0 | -2.6 |
| 2014 | 112.5 | 2.7 | 3.5 | 24.1 | 1.1 | 28.7 | 0 | -4.7 |
| 2015 | 113.3 | 4.3 | 4.2 | 22.8 | 1.1 | 28.1 | 0 | -2.6 |
| 2016 | 113.4 | 4.7 | 5.1 | 20.4 | 1.1 | 26.6 | 0.66 | -0.6 |
| 2019 | 113.8 | 5.1 | 9.5 | 19.1 | 1.2 | 29.8 | 9.05 | 0.4 |
| 2022 | 114.9 | 6.2 | 15.1 | 17.9 | 1.2 | 34.2 | 68.4 | 1.3 |

**Table 16. [THE NETHERLANDS] Scenario C results. Hypothesis is Scenario B plus reduced firm capacity from renewables.**

The firm capacity surplus in 2015 is reduced by 0.4 GW compared to variant B. In 2019 and 2022, the capacity surpluses disappeared. Given the assumptions in this scenario, in which a lower operating thermal capacity (no oldest gas-fired power plants) and a worse contribution of the other operating power (thermal and renewable) is counted, there is sufficient domestic generation capacity to meet the Dutch electricity demand up to 2019.

Scenario D

It is based on Scenario A with higher demand. Results are shown in Table 17. LOLE is only higher than 4.0 hours in 2022. As in previous scenarios, the non-operational capacity of 6.2 GW in 2022 is not used although the target is not met.

Figure 20 shows a comparison of the different scenario results. The 4 hours/year target is not met only in scenarios C and D after 2019 and 2022 respectively.

| Scenario D | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Demand (TWh) | Non-operational supply (GW) | Operational supply | | | | LOLE (hours) | Firm capacity (GW) |
| | | | RES | Thermal (except waste) | waste | total | | |
| 2011 | 118.2 | 0.0 | 2.4 | 23.1 | 0.8 | 26.3 | 0.0 | -3.2 |
| 2012 | 115.9 | 0.5 | 2.5 | 24.0 | 0.8 | 27.3 | 0.0 | -3.0 |
| 2013 | 115.6 | 0.8 | 2.8 | 22.7 | 1.0 | 26.5 | 0.0 | -2.6 |
| 2014 | 112.5 | 2.7 | 3.5 | 24.1 | 1.1 | 28.7 | 0.0 | -4.7 |
| 2015 | 114.9 | 4.3 | 4.2 | 23.8 | 1.1 | 29.1 | 0.0 | -3.6 |
| 2016 | 115.7 | 4.7 | 5.1 | 21.3 | 1.1 | 27.5 | 0.0 | -1.6 |
| 2019 | 118.4 | 5.1 | 9.5 | 19.9 | 1.2 | 30.6 | 0.6 | -0.7 |
| 2022 | 123.3 | 6.2 | 15.1 | 18.7 | 1.2 | 35.0 | 9.4 | 0.4 |

**Table 17. [THE NETHERLANDS] Scenario D results. Hypothesis is Scenario A with higher demand.**

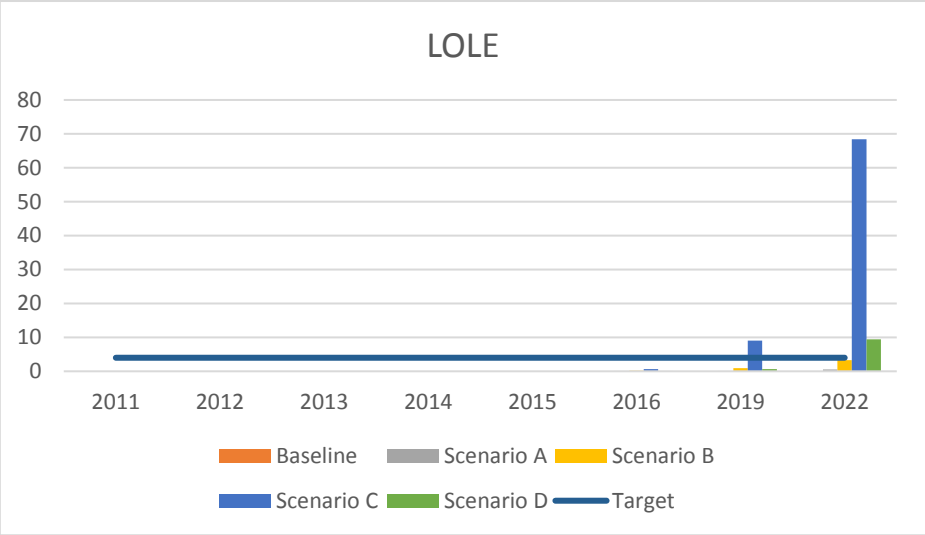



**Figure 20. [THE NETHERLANDS] Comparison of LOLE results among the different scenarios.**

In Table 17 the estimated generation capacity surplus or deficit is compared with the available transmission capacity for imports and exports. Available interconnection capacity is estimated considering reductions due to breakdowns, and maintenance. For each scenario, the ratio between the surplus or deficit in generation capacity and the available capacity is presented as a percentage. If the value is negative it means an export capacity. If the value is negative, it means an import need.

| Year | BG | GE | NO | GB | DK | Total | Availa-ble[1] | Base-line | Scenarios | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | A | B | C | D |
| 2014 | 1.7 | 2.4 | 0.7 | 1.0 | 0.0 | 5.9 | 5.5 | -85 % | -85 % | -85 % | -85 % | -85 % |
| 2015 | 1.7 | 2.5 | 0.7 | 1.0 | 0.0 | 6.0 | 5.5 | -63 % | -69 % | -55 % | -46 % | -65 % |
| 2016 | 1.7 | 2.5 | 0.7 | 1.0 | 0.0 | 6.0 | 5.5 | -44 % | -35 % | -22 % | -11 % | -29 % |
| 2019 | 2.4 | 4.5 | 0.7 | 1.0 | 0.0 | 8.7 | 8.0 | -27 % | -16 % | -8 % | 4 % | -9 % |
| 2022 | 2.4 | 4.5 | 0.7 | 1.0 | 0.7 | 9.4[2] | 8.7 | -15 % | -9 % | -1 % | 14 % | 5 % |

[1] Estimated taken into account reductions due to breakdowns and maintenance.
[2] EIncluded Cobra cable on 0.7 GW

**Table 18. [THE NETHERLANDS] Available interconnection capacity and comparison with the estimated generation capacity surplus/deficit..**

## Remarks

The Dutch report does not contain detailed information about the model. It highlights the increasing importance of the regional Pentalateral Energy Forum assessment. The assessment is based on the LOLE and it does not consider interconnection capacity until a second step where the surplus or deficit in the generation capacity is compared with the available interconnection capacity. The report provides a comparison with the Regional assessment performed in the Pentalateral Energy Forum and it is mentioned that the results in the case of an isolated country fit well with the results of this national assessment.

The report also highlights that, at present, there is considerable uncertainty in the market regarding investments in new conventional power plants, given the planned large quantities of new wind and solar installed capacities, the deterioration of the gas-fired plants economy and the developments of capacity markets in neighboring countries.

## 2.5 France

As established in the Energy Code, generation adequacy assessment is done by the French transmission system operator RTE every second year, with partial updates for the other years, in accordance with the Decree of 20 September 2006. The last report, 'Generation Adequacy Report on the electricity supply-demand balance in France' [17], covers the medium term of 5 years.

This assessment is driven by the launch of capacity mechanism in France and the 2015 report is the first time that the report coordinates with the Multiannual Energy Program, the steering tool of the energy transition.

### Methodology

Figure 21 shows an overview of the methodology used by RTE to assess generation adequacy. It is based on a probabilistic approach using a sequential Monte Carlo simulation performed on an hourly basis over annual samples.

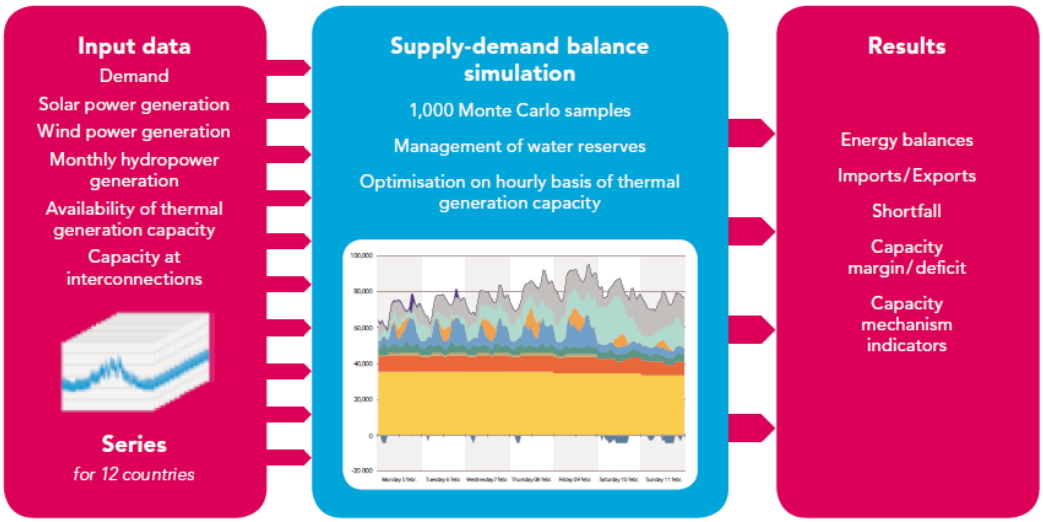



**Figure 21. [FRANCE] Overview of the methodology.**
**Source: *Generation Adequacy Report on the electricity supply-demand balance in France*, 2015 Edition.**

The generation adequacy assessment is carried out with respect to two situations:

- France is interconnected to first and second order neighbouring countries and modelled with a Net Transfer Capacity (NTC) model. The model takes into account the following 12 countries: Austria, Belgium, France, Germany, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Switzerland and the United Kingdom.
- France is a stand-alone entity with no cross-border interconnections.

The assessment is conducted through a hourly costs optimisation of the European power system over a 1 year time horizon, taking into account key events that can affect the energy balance: (1) cold spells/heat waves; (2) frequency and duration of outages or maintenance events; (3) variation in water availability that affects the hydro capacity; (4) variable wind and photovoltaic generation, modelled into synchronised generation series to take into account the correlation of renewable output. Random load and supply curves are generated and combined into 1000 samples. The Monte Carlo simulation returns an estimation of both potential shortfall and energy balance for each case.

## Demand

To make sure that only structural trends in electricity demand are considered in the model of demand, gross electricity consumption figures are adjusted for climate effect ([1]), demand response measures, calendar effect, etc. The model of demand is built with respect to four scenarios (Table 19) that include different assumptions on the main sources of uncertainties in the medium term: (1) changes in the structure of the consumption by sector (residential, tertiary, industry, transport energy and agriculture sectors and losses from the power transmission): (2) diffusion of DSM and energy efficiency in buildings and equipment; (3) new end-uses; (4) demographic changes.

The analysis is performed considering only the mainland, and it does not consider the demand due to uranium enrichment (the shift from gaseous diffusion to centrifugation has resulted in a sharp contraction in electricity consumption). Reference temperatures are estimated with data from Météo- France, based on observations made over the last 30 years. Since the time horizon of the assessment is short (5 years), it does not take into account future changes in the climate.

| | Baseline | Low variant | Stronger DSM | High variant |
|---|---|---|---|---|
| Main assumptions | Central | Reduced consumption | More energy efficiency | Higher consumption |
| GDP | Central Medium annual growth 1.5% | Low Medium annual growth 1.2% | Central Medium annual growth 1.5% | High Medium annual growth 1.9% |
| Energy efficiency | Central | Central | Greater effect | Lesser effect |
| Demographics | Central | Low | Central | High |
| Relative price of electricity | Central | Low | Central | High |

**Table 19. [FRANCE] Main assumptions of the different demand scenarios.**

The trend in electricity demand over the next 5 years is showed in Figure 22, with details on the contribution of each sector.

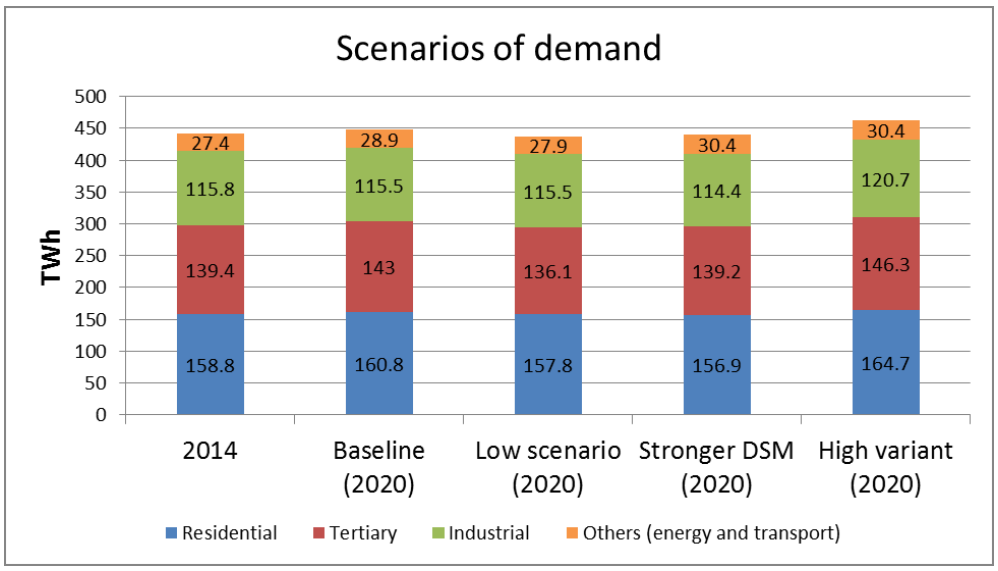



**Figure 22. [FRANCE] Scenarios of demand.**

Regarding the evolution of the peak demand, although in the last decade peak demand increases two or three times faster than energy consumption, the estimation over the 2015-2020 period is based on the same growth rates than energy demand. Due to the high percentage of electric heating in France (one third of

([1]) Demand is estimated in France and Europe from 100 temperature driven demand scenarios (years) generated by the Météo-France research centre to represent all the posible climate situations as cold spells and heat waves.

residences in France, representing some 9.8 million homes), demand is more sensitive to colder temperatures: this sensitivity is estimated at 2400 MW per degree Celsius at 19:00 (peak demand time).

It is also expected that new end-uses or changes in the technologies that power them will gradually change the power load profile.

For the neighbouring countries, three different demand scenarios are assumed: the high, baseline and low scenarios with average annual demand growth of 0.7%, 0.3% and 0.2% respectively. Temperature sensitivity is less pronounced than the French case, so severe weather is less relevant than in France.

## Generation

The key factors that can affect the availability of power supply and that are taken into consideration in the report are: (a) variation in water flows that can change the availability of hydro capacity for weeks and months; (b) synchronous series of wind and photovoltaic generation — also with the other European countries considered — that take into account the spatial correlation of renewable output across countries; (c) availability of conventional generators. Figure 23 shows the expected installed capacity for each technology by 2020.

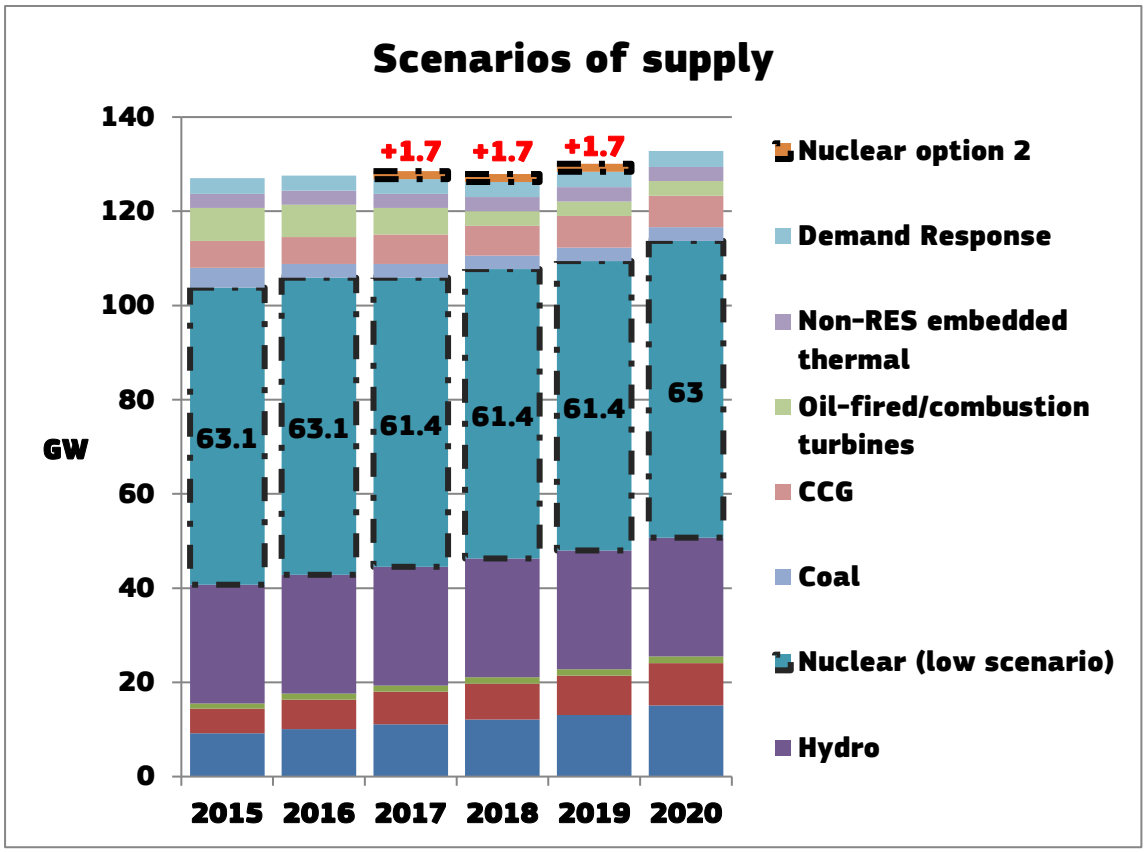



**Figure 23. [FRANCE] Expected installed capacity by technology by 2020. Nuclear option 2 assumes the commission of Flamanville nuclear power plant immediately after the decommission of Fessemheim. Option 1 assumes a reduction of the nuclear installed capacity of 1.7 GW from 2017 to 2019.**

The main assumptions for each technology are as follows:

- Onshore wind power. Historical data averages around a capacity factor (or load factor) of 22.9% over the past five years. Monthly load factors are more unequal, ranging from 20 to 40%, showing a seasonal pattern with the maximum and minimum values in winter and summer respectively. Time series were built by RTE from the ENTSO-E database, considering different load factors measured on an hourly basis at the different countries to take into account the spatial correlation among them.

- Solar photovoltaic. The average load factor of PV is 14% and it ranges from 5% in December to more than 20% in summer. The daily periodicity of solar production is gradually changing the price daily pattern as it can be seen currently in Germany and Italy. Similarly to wind, annual time series are generated by RTE from the ENTSO-E database.
- Bioenergies. The largest biomass generation project has 150 MW of installed capacity. It is expected to run 7500 hours/year which implies a load factor of 85%.
- Hydropower. Installed capacity has not changed too much in the last 25 years. The impact of annual rainfalls widely affects the hydropower generation from one year to the next. This aspect is considered in the probabilistic approach. Pumped hydro storage — that accounts for 4.3 GW of capacity — is included in the modelling of the hydropower capacity. No information is provided as for wind and solar, regarding the creation of the annual time series.
- Nuclear. The two scenarios for nuclear installed capacity differ from the dates of decommissioning of Fessemheim (2016 or 2019, after the commission of the new reactor at Flamanville that will compensate for the loss of the first one). Availability of nuclear capacity is based on the historical data and is higher in winter than in summer (when most of the maintenance work is done). Availability considering only scheduled maintenance is 85% and unscheduled unavailability is 2-3%. As scheduled maintenance is mainly done during summer months, it is assumed 90% of average availability for winter months.
- Fossil-fired capacity. These conventional technologies have been affected by a number of changes in the environmental and economic situation in the recent years. The main drivers are: (1) reduction in power demand due to the economic crisis; (2) the relative price of oil and gas together with the low level of ETS carbon prices; (3) European environmental regulation on large combustion plants directive and industrial emission directive. The key assumption is the tempory mothballing of some power plants.
- Demand response. Incentivised reduction of power consumption can contribute to (1) meeting demand peaks and (2) preventing situations of capacity shortfalls. There are three different kinds of demand response mechanisms used in France: tariff options, that combine high/low consumption tariffs corresponding with highest/lowest electricity generation prices; contracts between consumers and their suppliers setting specific conditions for load shedding amounts, duration, frequency, and authorised activation periods; and market-based demand response, where consumers can participate to balancing markets by submitting 'upwards' bids, Other measures, like tenders for rapid reserve (1000 MW) and complementary reserves (500 MW) are in place to insure additional demand response capacity.

## Scenarios

Demand is analysed with four different scenarios (Baseline, High, Low and Stronger DSM) and supply is estimated considering two scenarios with different nuclear capacity.

A sensitivity analysis is performed in the baseline scenario, considering an isolated system.

## Consideration of reserves

It is included as demand response available capacity.

## Interconnections

For the case of France as an interconnected system, the net transfer capacity is used to model the availability of generation capacity of France's first and second order neighbouring countries (Austria, Belgium, Germany, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Switzerland and the United Kingdom). Although cross-border exchanges are based on flow-based calculation since 21 May 2015 between Belgium, Germany, France and the Netherlands , the report still assumes NTC to model exchange capacities. In 2013, the import and export capacity was 9 and 12 GW respectively. In 2020 these capacities will be 11.4 and 17.3 GW.

## Indicators

The generation adequacy in France is assessed with respect to two categories of indicators:

- Risk indicators;
- Flexibility requirements measured by residual demand.

Risk indicators. LOLE, which is compared to the target level set at 3 hours per year. The report is not intended to draw conclusions on the possible remedies to shortfall risks. For a LOLE below/above 3 hours, a capacity margin/capacity gap is estimated to reach the target value.

Other estimated indicators are Expected Energy Not served (EENS), exchange balance, energy from different technologies, estimated $CO_2$ emissions, etc.

Flexibility requirements. The variability and limited predictability of wind and photovoltaic generation can have a direct impact on the functioning of the power system and its efficiency. The report assesses the daily and weekly flexibility needs of the French system over the long term by means of two scenarios for 2030: 'Diversification' and 'New Mix' scenarios. Scenarios differ on assumptions on: (1) power demand; (2) energy efficiency; (3) one-in-ten peaks; (4) wind and photovoltaic capacity.

## Results

### Risk indicators

The results for the baseline demand scenario considering the two hypotheses for nuclear capacity are presented in Figure 24. The report also includes the analysis of the French system without the commissioning of EPR nuclear power plant in 2019. A more critical situation is foresees for the case of a loss of the available interconnection capacity with neighbouring countries, which will lead levels of LOLE ranging from 14 to 34 hours (see Table 20).

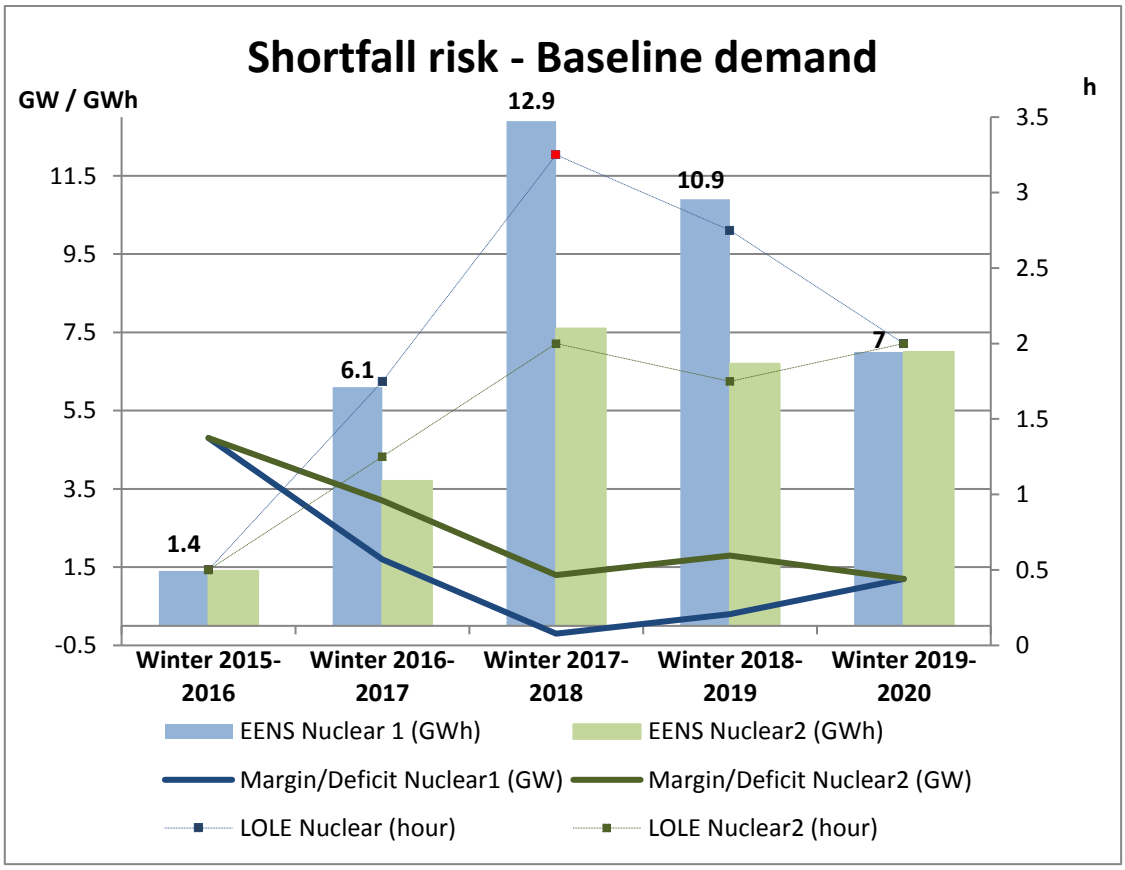



**Figure 24. [FRANCE] Adequacy Assessment. Baseline demand scenario and two different options for nuclear capacity. Option 1 and Option 2 refer to the shutdown of the Fessenheim nuclear power plant in 2016 and when EPR is commissioned, in 2019, respectively.**

| Baseline Demand | Scenario | EENS (GWh) | LOLE | Capacity margin / deficit (MW) |
|---|---|---|---|---|
| Winter 2015-2016 | Nuclear 1 | 1.4 | 0h30 | 5 |
| | Nuclear 2 | 1.4 | 0h30 | 5 |
| | No interconnection. | 53.8 | 14h00 | -4.6 |
| Winter 2016-2017 | Nuclear 1 | 6.1 | 1h45 | 2 |
| | Nuclear 2 | 3.7 | 1h15 | 3.2 |
| | No interconnection. | 85.1 | 20h00 | -5.4 |
| Winter 2017-2018 | Nuclear 1 | 12.9 | 3h15 | -0.2 |
| | Nuclear 2 | 7.6 | 2h00 | 1.3 |
| | No interconnection. | 458.9 | 34h00 | -7.2 |
| Winter 2018-2019 | Nuclear 1 | 10.9 | 2h45 | 0.3 |
| | Nuclear 2 | 6.7 | 1h45 | 1.8 |
| | No interconnection. | 128.8 | 28h00 | -6.6 |
| Winter 2019-2020 | Nuclear 1 | 7.0 | 2h00 | 1.2 |
| | Nuclear 2 | 7.0 | 2h00 | 1.2 |
| | No interconnection. | 133.2 | 30h00 | -6.7 |

**Table 20. [FRANCE] Shortfall risk results by generation and transmission scenarios with respect to 'baseline' demand. No interconnection assumes Fessenheim shut down when EPR is commissioned (nuclear 2).**

Some sensitivity analysis is carried out with respect to:

- Energy efficiency, that contributes to reduce power demand but also plays an important role in the reduction of peak demand and the limitation of risk of security of supply;
- Extreme events which include the most unfavourable combinations of variables among the 1000 simulated, occurring with a probability ranging between 1-in-10, 1-in-20 and 1-in-1000.

### Flexibility requirements for 2030

Under specific assumptions of power demand, energy efficiency, peak demand and renewable generation capacity (Table 21), this section of the report identifies the impacts of a high share of renewables on the residual load (gross power demand, from which is subtracted must-run and renewable generation).

| Scenarios for 2030 | Power demand (TWh) | Energy efficiency (TWh) | 1-in-10 peak (GW) | Wind capacity (GW) | Solar capacity (GW) |
|---|---|---|---|---|---|
| Diversification | 501 | 79 | 105 | 30 | 16.4 |
| New Mix | 480 | 105 | 100 | 37 | 24 |

**Table 21. [FRANCE] Scenarios for flexibility requirements assessment for 2030.**

From the simulation of the power dispatch for 2030, results show that the higher the penetration of wind and solar is, the lower the contribution of conventional generation is ([2]) — especially during the week days

([2]) Here conventional generaion is to be interpreted as opposed to renewable generation.

— to cover load; the higher the flexibility requirement that can be provided by dispatchable units. Increases in solar power change the daily shape of the residual load during the midday hours, while increases in wind power attenuate the weekly periodicity of load.

This assessment would lead to the quantification of the flexibility requirements, which are in fact intrinsically related to the variability of the residual load.

### Remarks

The report on generation adequacy for the French system is aimed at assessing the risk of shortfalls of generation capacity under different demand scenarios and generation/transmission availability cases. France uses a sequential Monte Carlo simulation to assess adequacy, considering storage and the interconnection capacity with the neighbouring countries. In all, 12 countries are modelled. Very detailed information about the estimation of future demand and installed capacity is provided throughout the report. The last edition of the report (2015) adds two new sections. One is on the assessment of daily and weekly flexibility requirements of the system under high shares of renewables for 2030 and the second refers to the assessment of the need for a capacity mechanism, which is already operational since 1 April 2015.

## 2.6 Ireland and North Ireland

Generation adequacy assessment is done by the Irish transmission system operator EirGrid which is required to publish forecast information about the power system, as set out in Section 38 of the Electricity Regulation Act 1999 and Part 10 of S.I. No 60 of 2005 European Communities (Internal Market in Electricity) Regulations. Similarly, SONI, the TSO in Northern Ireland, is required to produce an annual Generation Capacity Statement, in accordance with Condition 35 of the Licence to participate in the Transmission of Electricity granted to SONI Ltd by the Department of Enterprise Trade and Investment.

The report 'All-Island Generation capacity Statement 2016-2025' (see [18]), is a joint report done by EirGrid and SONI. The report assesses generation adequacy at two different levels:

- At country level (for Ireland and Northern Ireland separated) for the period 2016-2025,
- At island level (for both systems combined, i.e. on an all-island basis) for the period 2019-2025 when the second North-South Interconnector is commissioned.

### Methodology

The adequacy of the generation portfolio is determined by the level of LOLE calculated through the AdCal software. It is an analytical probabilistic model whose basis is a generation model represented by a capacity outage probability table (COPT). The COPT is estimated recursively, inserting each generation unit one at a time until the COPT is totally formed. Then, the probability of supply not meeting demand is calculated for each half-hour period. Then, they are summed to get the annual LOLE estimation.

The LOLE is then elaborated and results of the adequacy assessment are reported in MW, which refer to the amount of generating capacity that either exceed or lack with respect to the standard level of LOLE. When the system has a deficit, it means that a number of MW of capacity needs to be added to the generation portfolio to guarantee the standard level of LOLE. In the same way, in case of surplus, it means the generating capacity could be removed without affecting the adequacy of the system.

### Demand

As the drivers for economic growth and energy policies can vary from one jurisdiction to the other, demand is estimated independently for Ireland and Northern Ireland and then combined to produce the all-island forecast. The main drivers of energy demand that are taken into consideration are shown in Table 22.

The main characteristics of the model of demand used for Ireland and Northern Ireland are:

- The effect of temperature on demand. Demand peak data are adjusted to Average Cold Spell (ACS) temperatures; this approach leads to peak demand at average temperatures and removes sudden changes due to extreme weather conditions.

- Economic forecasts.
- Energy policies.
- Typical load shapes.

All-island demand forecast is the sum of the Irish and Northern Ireland forecasts. Peak demand forecasts do not coincide in the two regions, therefore a specific peak demand forecast for the All-island case has been built based on the demand shape in 2014 and the future Average Cold Spell conditions.

| | **Ireland** | **Northern Ireland** |
|---|---|---|
| **Methodology** | Multiple linear regression: electricity demand based on changes in economic parameters. Personal Consumption ([3]) and adjusted GNP ([4]). | Not clearly specified. The main economic parameter is Gross Value Added. |
| **Historical data** | Last 20 years to capture the most recent trends relating the economic parameters to demand patterns. Losses are 7-8 %. | No specific reference is made. |
| **Forecasting other key drivers for electricity demand** | Data centres (currently 250 MVA installations; 600 MVA in the connection process; 1100 MVA new enquires by 2025). Self-consumption from CHP generators. | Temperature. Self-consumption from embedded generation (estimated from the Renewable Obligation Certificate Register). Energy efficiency. |
| **Demand scenarios** | Low scenario: 50% of data centres in connection process will be connected. | Low scenario: based on relatively high temperature year, higher energy efficiency and pessimistic economic factor. |
| | Medium scenario: 100% of data centres in connection process will be connected. | Median scenario: based on an average temperature year, including energy efficiency and central economic factor. |
| | High scenario: Median scenario + 50% of new enquires of data centres. | High scenario: low temperature year, lower energy efficiency with optimistic economic factor. |
| **Peak demand forecasting** | The peak demand model assesses the Annual Load Factor (ALF) given by the average load divided by the peak load. This factor is corrected by the effects of Demand Side Management and temperatures. After, this forecast is tempered by Energy Efficiency savings. | The peak demand model for Northern Ireland is similar to the one of Ireland. |

**Table 22. [IRELAND AND NORTHERN IRELAND] Main drivers of energy demand taken into account in the generation adequacy methodology for Ireland and Northern Ireland.**

Figure 25, Figure 26 and Figure 27 feature the demand scenario forecasts for the three levels of analysis, with focus on Total Energy Requirement (TER), peak demand (TER peak) and Transmission peak by demand scenarios.

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([3]) Personal Consumption of Goods and Services (PCGS) measures consumer spending on goods and services, including such items as food, drink, cars, holidays, etc.

([4]) GNP is adjusted for the effect of re-domiciled companies, i.e. foreign companies which hold substantial investments overseas but have established a legal presence in Ireland.

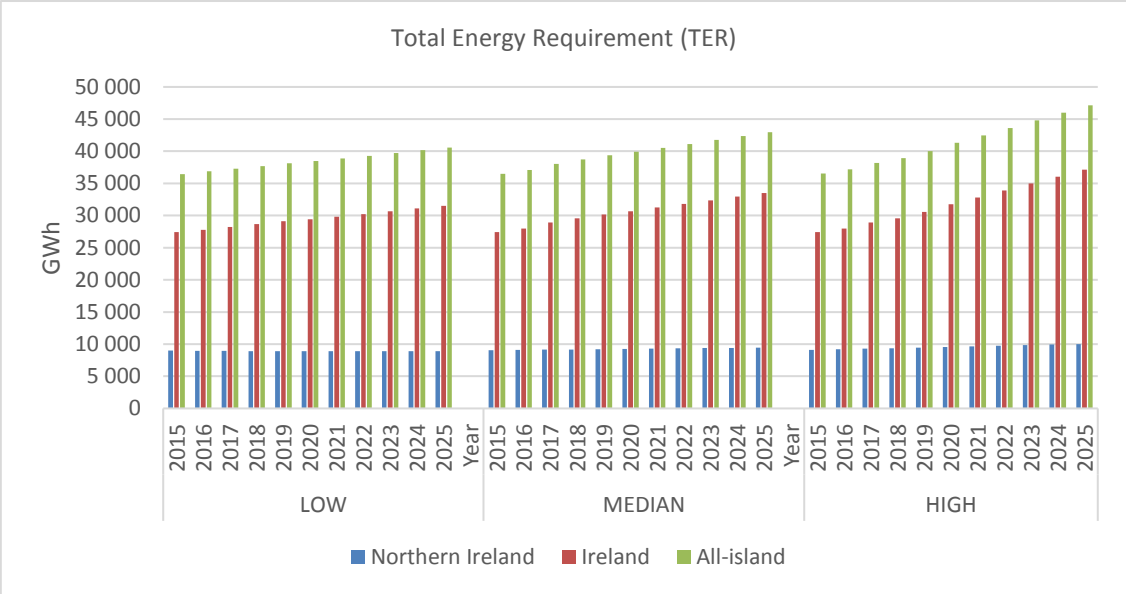


**Figure 25. [IRELAND AND NORTHERN IRELAND] Demand scenario forecasts.**

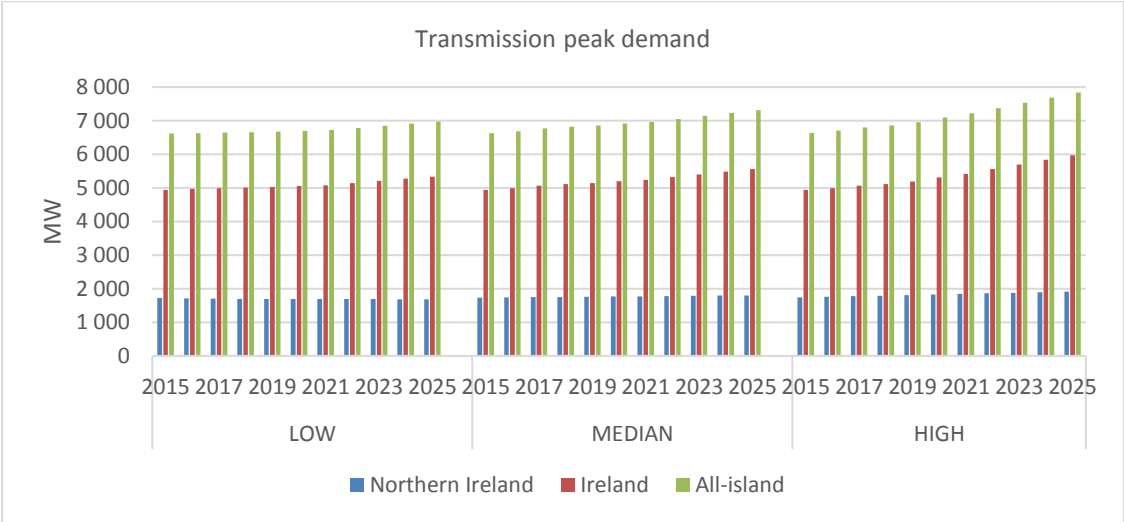


**Figure 26. [IRELAND AND NORTHERN IRELAND] Transmission peak demand.**

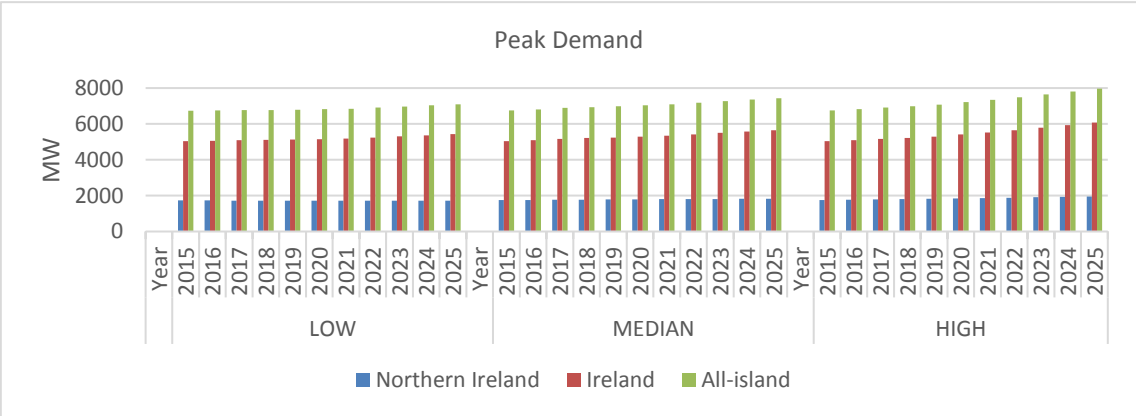


**Figure 27. [IRELAND AND NORTHERN IRELAND] Peak demand.**

## Generation

The model of supply takes into account the installed capacity, plant availability, and capacity credit of wind, demand side management and interconnection capacity. The last two elements are addressed in next sections of this report.

The report distinguishes between three different categories of **installed generation capacity:**

- Dispatchable generation, which includes pump hydro storage technologies and the interconnectors.
- Non-dispatchable generation, whichis the set of generators not connected to a control centre and whose operation cannot be controlled by the TSO. It is connected to the lower voltage distribution system and made up of many small units.
- Partially dispatchable generation, which is given only for Ireland. This generation plants' output can be reduced by the TSO controllers if required.

Assumptions on the installed capacity for conventional technology is based on commissioning dates and the shutdown of the oldest conventional power plants, taking into account the provisions of the IED directive.

Storage is estimated without considering the Compressed Air Energy Storage (CAES) Plant in the Larne area.

Figure 28 and Figure 29 describe the changes in fully dispatchable and non dispatchable plant capacities which are forecast to occur in Ireland and Northern Ireland and the partially dispatchable plant capacity in Ireland over the next ten years. Fully dispatchable generation includes 104 MW of extra planned installation from 2017. The share of non-dispatchable capacity over the dispatchable capacity of plants increases in both regions over the time period.

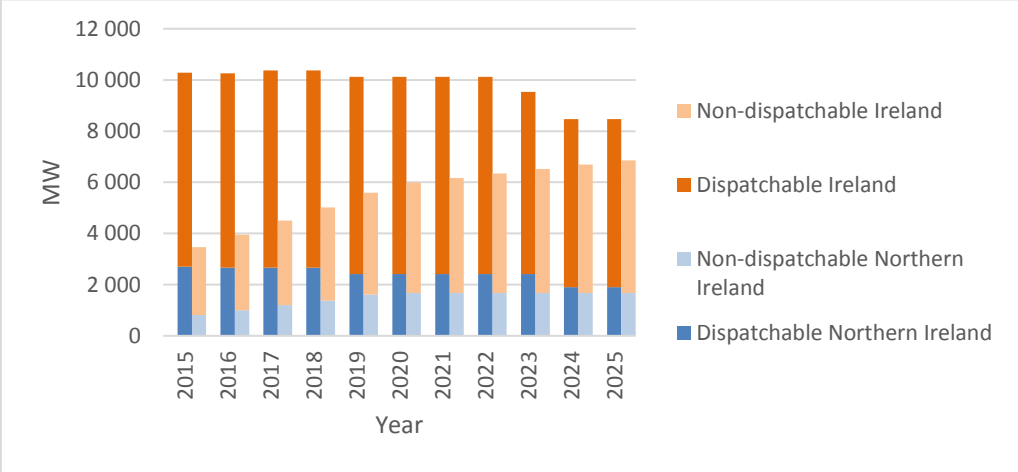


**Figure 28. [IRELAND AND NORTHERN IRELAND] Dispatchable versus non-dispatchable generation.**

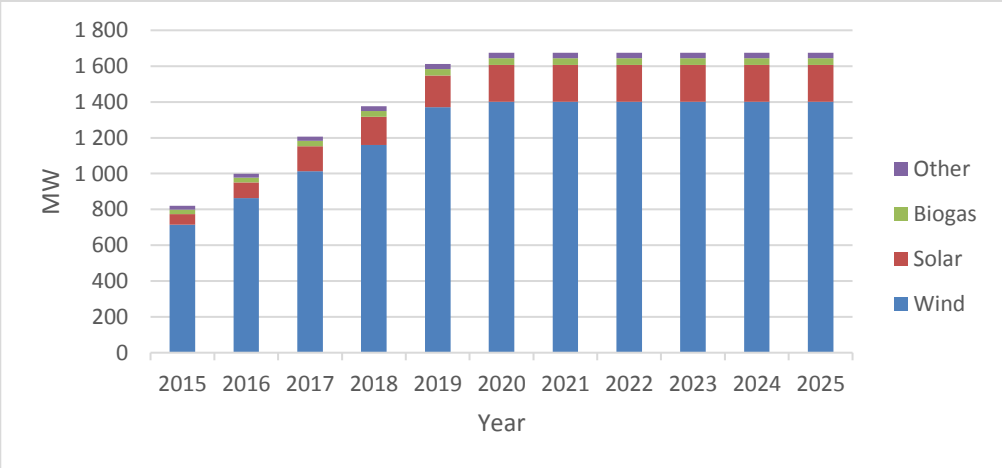


**Figure 29. [IRELAND AND NORTHERN IRELAND] Partially dispatchable generation in Ireland.**

Assumptions on the installed capacity for renewable technology (including partially dispatchable renewable technologies) are based mainly on the generation target for renewables, which is 40% of the electricity consumption for both systems by 2020. The main increase in total installed capacity is foreseen for wind (Figure 30 and Figure 31).

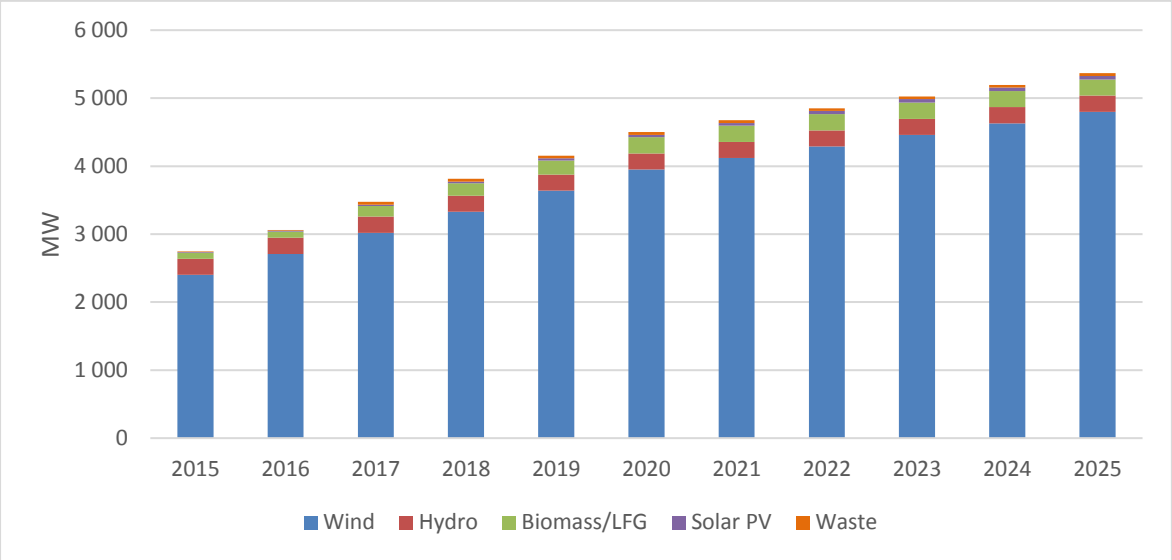


**Figure 30. [IRELAND AND NORTHERN IRELAND] Renewable generation in Ireland.**

**Plant availability** is given in terms of Forced Outage Rate (FOR) and it is estimated from historical data of plant availability considering high impact, low probability (HILP) events which produce a more conservative estimation of availabilities than the one coming from the plant operators. Forced outage rates (FOR) have decreased recently because of the substitution of old generators with new ones, the demand reduction and also after the introduction of the Single Electricity Market (SEM) where incentives have been put in place to encourage better generator availability.

The increase of generation coming from renewables will change the availability pattern of dispatchable generators as generators will be switch off in night or minimum load times. This will require additional maintenance and increased scheduled outage days. The TSOs are already monitoring this change.

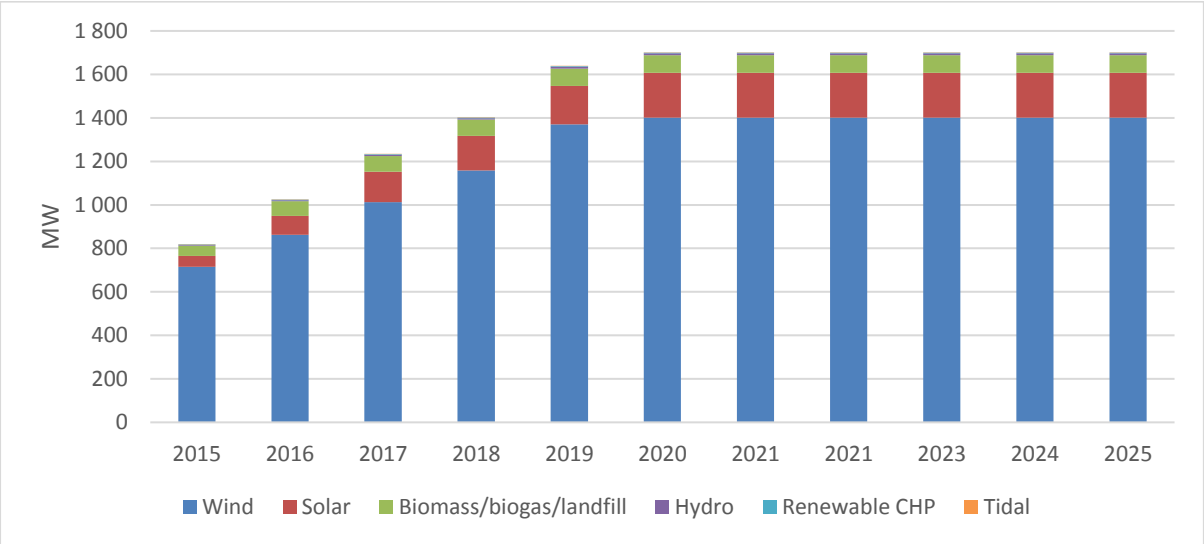


**Figure 31. [IRELAND AND NORTHERN IRELAND] Renewable generation in Northern Ireland.**

**The capacity credit for wind** is the amount of capacity (MW) of wind generation that contributes to generation adequacy. It is determined by subtracting a forecasted wind's half-hourly generation from demand. This 'lower demand effect' produces a better adequacy position, which is translated in extra capacity (MW) of an installed conventional power generation plant (perfect plant). This extra amount of capacity in the assessment is the wind capacity credit of wind (Figure 32). For Ireland, the 2012 profile is used as a reference as it is very close, in terms of capacity credit of wind, to the average value of the last years. For Northern Ireland, the wind profile is based on an average over several years. Due to the increase of the geographical scope, the capacity credit for the all-island assessment is higher than the value obtained for the two systems individually.

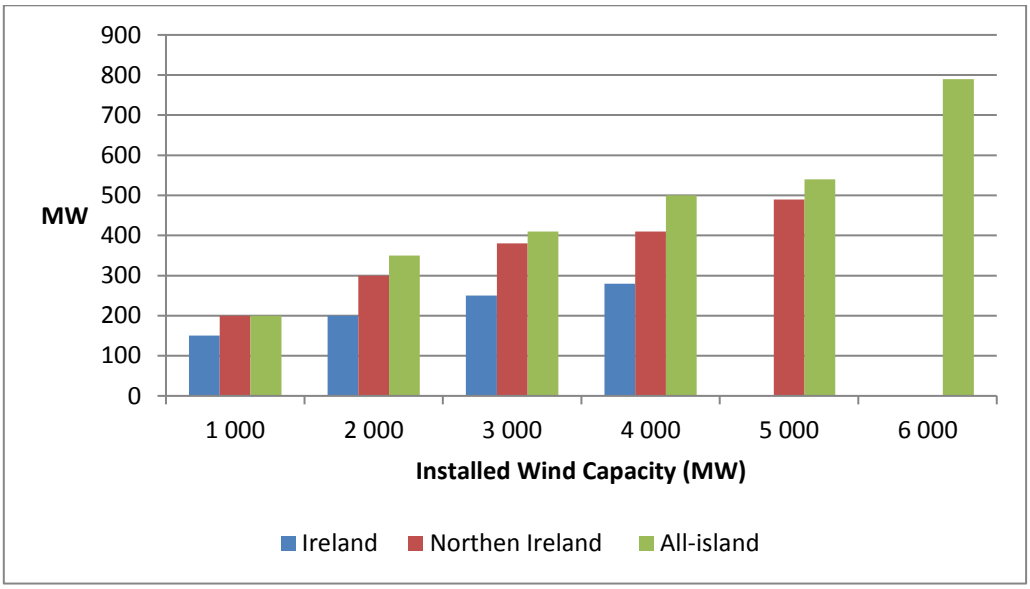


**Figure 32. [IRELAND AND NORTHERN IRELAND] Assumed Wind Capacity Credit for the three levels of assessment.**

## Interconnectors

The generation adequacy assessment takes into account the capacity interdependence between the Northern and Southern parts of the island (100 MW for North to South flows and 200 MW for South to North). From 2019 the assessment takes into account the contribution of the second North-South interconnector that will eliminate the current physical constraints between the two systems.

Due to the reduced available capacity from Great Britain in future years, interconnections with Great Britain have been modelled with 75 % of their import capacities to reproduce the limited available capacity in Great Britain. Regarding the Moyle interconnector between Northern Ireland and Scotland, issues with transmission access rights in Scotland may limit its export capacity to 80 MW from 2017.

For a more realistic representation of the Capacity Reliance of the system the report includes the interconnectors with GB (the Moyle 450 MW and the East-West interconnector's 500 MW) to the assessment, including the available capacity of generation and the peak demand in GB.

## Demand Side Management

Demand Side Management schemes are currently in place in Ireland and Northern Ireland, where it currently accounts for 230 and 18 MW of capacity respectively. Ireland is currently adopting a Demand Side Units (DSUs) scheme where medium and large industrial premises, possibly aggregated by a DSU aggregator, can be dispatched by the TSO as they were generators. Dispatchable Aggregated Generating Units (AGUs) operate in Northern Ireland; they consist of a number of individual diesel generators grouping together to make their combined capacity available to the market.

Extra demand side measures will deem the foreseen reduction of power imports from Great Britain.

## Scenarios

Scenarios (see Table 23) are based on different assumptions on demand, generation capacity availabilities and interconnection capacities with Great Britain.

| | Demand | Plant availability | Interconnection to GB |
|---|---|---|---|
| Northern Ireland | Median | Estimated by TSO | Yes |
| | Low | Estimated by TSO | Yes |
| | High | Estimated by TSO | Yes |
| | High | Low | Yes |
| | Median | Estimated by TSO | No |
| Ireland | Median | Estimated by TSO | Yes |
| | Low | Estimated by TSO | Yes |
| | High | Estimated by TSO | Yes |
| | Median | Estimated by TSO | No |
| All-island | Median | Estimated by TSOs | Yes |
| | Median | Estimated by TSO | No |

**Table 23. [IRELAND AND NORTHERN IRELAND] Scenarios for the assessment.**

## Consideration of reserves

It is not mentioned in the report.

## Indicators

LOLE is used as the security standard. Ireland and Northern Ireland have a target or reference value of 8 and 4.9 hours per year respectively. The security standard for all-island calculations is 8 hours.

## Results

The surplus/deficit resulting from the generation adequacy assessment represents the amount (in MW) of installed capacity that exceeds/is required to set the system at the target level. Results are shown for Ireland alone, Northern Ireland alone and on an All-island basis. The single area studies are relevant until the second interconnector between both systems will be commissioned (late 2019). Nevertheless results are shown for the entire period (10 years) to reflect the effects of delays in commissioning this interconnector. Similarly, the results for the combined system will be valid only after the commissioning of the second interconnector but it reflects the benefits of a regional scope.

Figure 33 shows the results for the single area studies considering the different assumptions for demand.

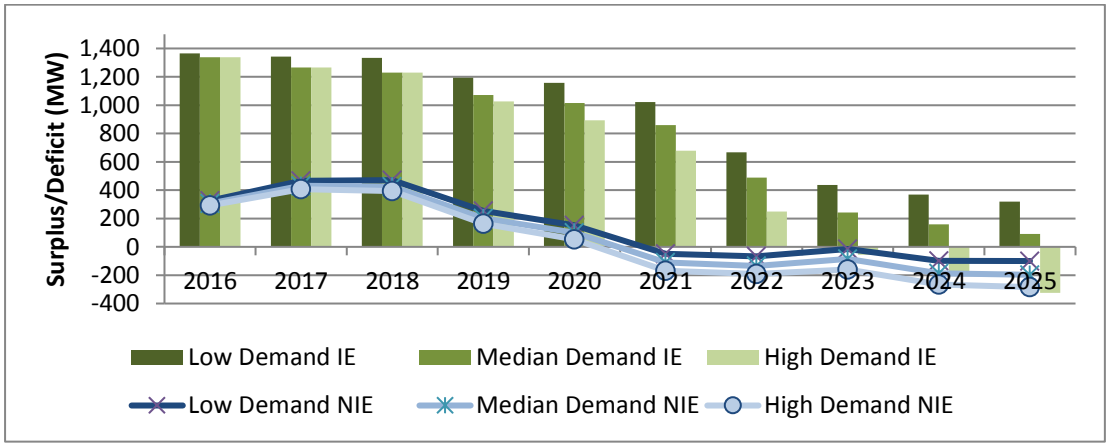


**Figure 33. [IRELAND AND NORTHERN IRELAND] Adequacy results for the Country scenarios. Ireland and Northern Ireland (median availability of power plants).**

Figure 34 shows the results for the base case scenario. The result for the All-island case is always higher than the Irish case even when there is a deficit of generation capacity in Northern Ireland. The capacity surplus for the case of no interconnection to Great Britain is reduced drastically for all cases and Northern Ireland would be in deficit from 2019. Moreover, Irish generation capacity margin starting from 2021 is higher than the All-island case when Northern Ireland has a significant deficit of generation. This again, highlights the role of interconnectors in adequacy studies and their importance from the security of supply point of view.

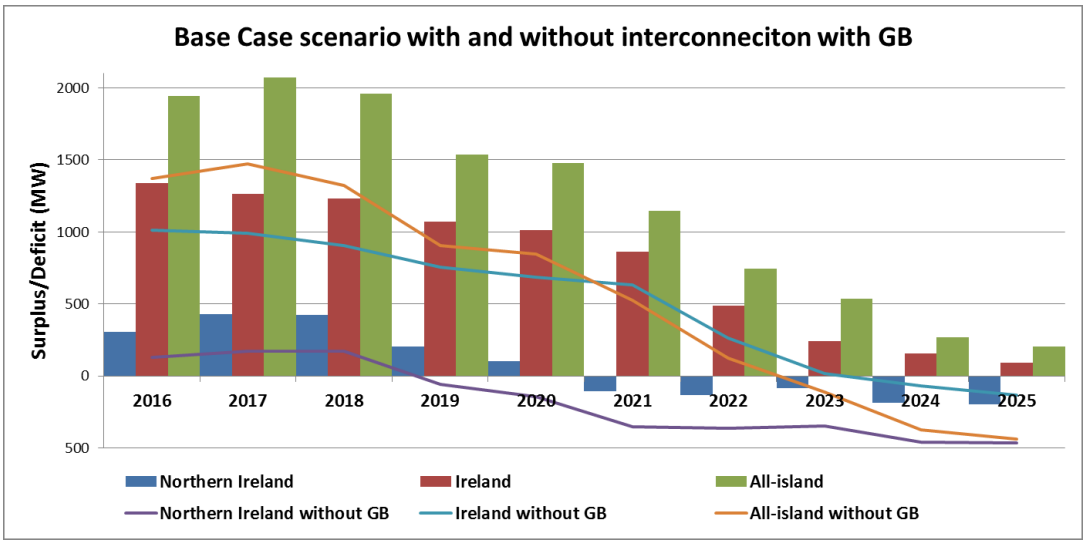


**Figure 34. [IRELAND AND NORTHERN IRELAND] Adequacy results for the base case scenario with and without interconnection to Great Britain.**

Need for Capacity Remuneration Mechanism

In the 2016 edition of the generation adequacy assessment the analysis has also considered the requirement for a Capacity Remuneration Mechanism (CRM) within the Integrated-Single Energy Market, which is a design for an energy-only market which will be implemented soon in the Irish island with the aim of fostering market integration with the GB and European electricity markets. This analysis foresaw the completion of the following steps:

- Assumptions: All-island case; period 2016-2025; stochastic approach to the study of multiple wind, demand and outages profiles; priority of dispatch to renewable generation; connection to the British power system with 75 % interconnectors import reliance.
- Definition of Capital and O&M costs for each generation unit;
- Implementation of a cost minimising unit commitment and dispatch model in PLEXOS® integrated energy model to generate data on power production;
- Assessment of revenues from energy sales and provision of ancillary services remunerated at the system service tariffs. Two cut-off price levels are distinguished: (a) 3000 euros/MWh and (b) 11000 euros/MWh.
- Identification of an updated portfolio of generator units based on the criteria whether generator units recover the capital and O&M costs or only capital costs;
- With the new portfolio the adequacy study is carried out and new level of deficit/surplus of capacity is defined. A negative result of this analysis should be interpreted as the capacity shortfall that exists in the assumed energy only market.

Results for the different assumptions are shown in Figure 35.

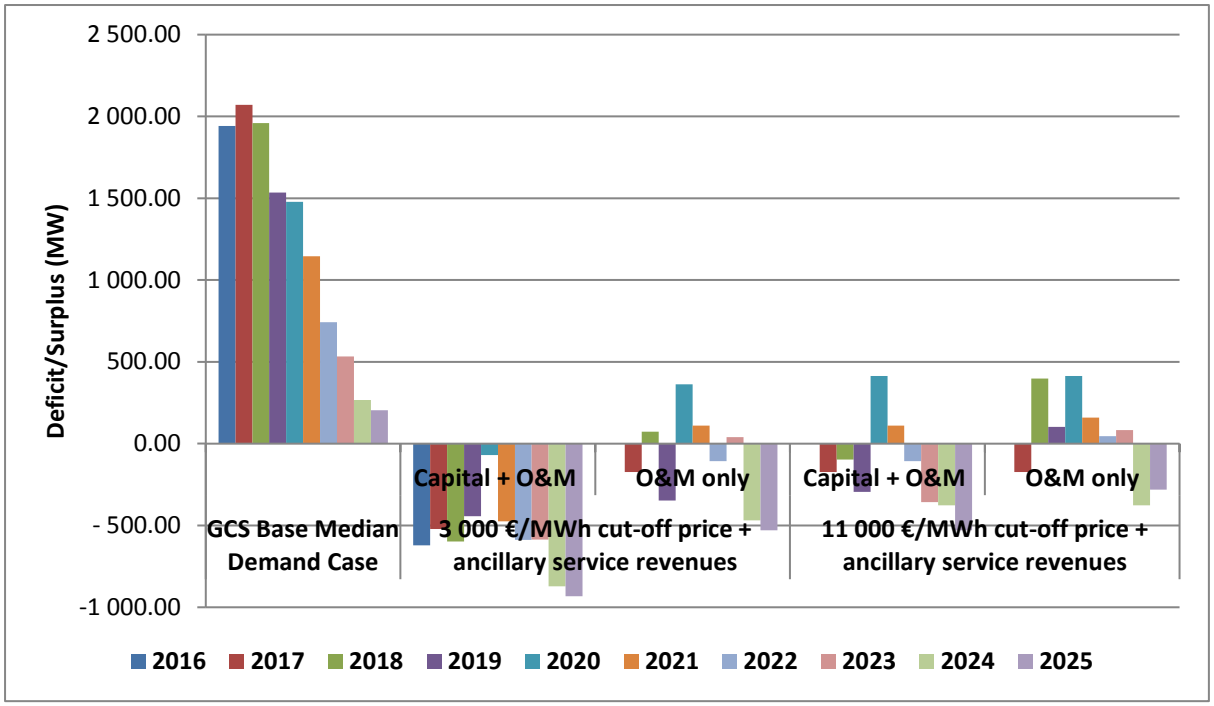


**Figure 35. [IRELAND AND NORTHERN IRELAND] Comparison of results of adequacy levels between Generation Capacity Statement (GCS) approach and the Energy-only market approach.**

### Remarks

SONI and EirGrid use an analytical probabilistic model to assess adequacy, considering storage, and the interconnection capacity with Great Britain. Through the report, the importance of the interconnection is highlighted several times. Also very interesting is the comparison between the assessment for each system individually, and both of them together. Reserves and possible flexibility issues cannot be assessed with the AdCal model.

A standard GAA can be considered the upper bound assessment of the adequacy of the generation fleet in the system, although an analysis of the economic conditions offered by the market would refine the analysis considerably and add more elements for the evaluation of the system evolution. The level of adequacy that results once market forces are included in the simulation gives the start point for and the evaluation of possible measures to reach the target level of adequacy. These could be, among others, CRM, new design of ancillary services market, increased level of market integration, removal of subsidy to market participants, etc.

## 2.7 UK

Until 2014, Ofgem, Great Britain's TSO, had to provide the Secretary of State with an annual Electricity Capacity Assessment report by 1 September each year. The Department of Energy and Climate Change has removed this obligation from 2015 onwards, after the decision to introduce a capacity market from winter 2018/2019. To inform the level of capacity to procure in this Capacity Market, the Government requires National Grid to provide it with a recommendation. The results of this new analysis are summarised in the 'National Grid EMR Electricity Report' ( [19]).

The focus of this work is the Generation Adequacy Methodology in each Member State. What is presented in the following sub-sections is the Electricity Capacity Assessment Report 2014 (see [20]).

### Methodology

The assessment is done using a non-sequential Monte Carlo probabilistic model. The objective is to estimate the distribution of the surplus Z as Z=X+W-D where X is the available conventional generation capacity, W is

the wind generation capacity and D the electricity demand. Z is built through convolution of the distributions of X, W and -D, which assumes independency between the random variables to sum-up (see Figure 36). The different scenarios (projected generation and demand) where the assessment is performed, are based on National Grid Future Energy Scenarios (FES).

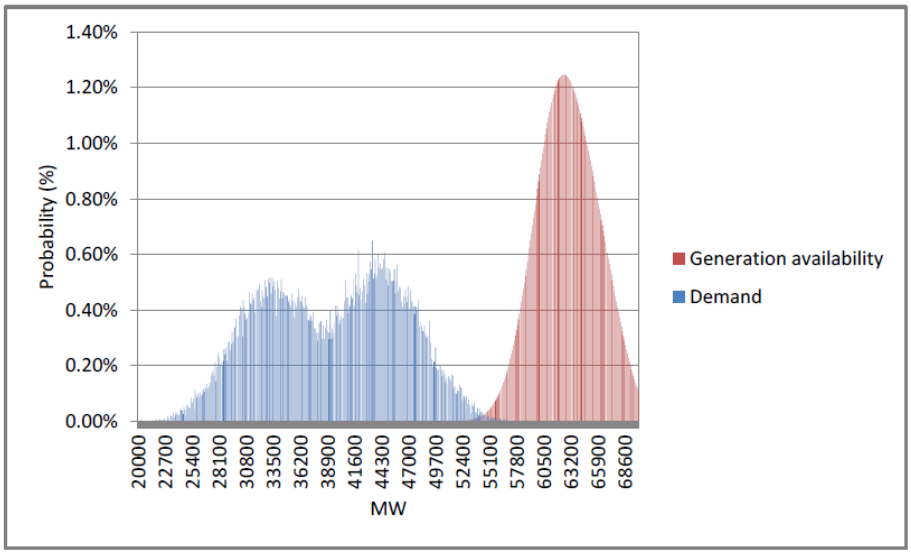


**Figure 36. [GREAT BRITAIN] Estimated demand and generation capacity distributions.**
**Source: *Ofgem Electricity Capacity Assessment Report 2013*.**

A complete overview of the modelling approach is presented in Figure 37: green boxes represent input data based on historical data, blue boxes represent inputs based on Ofgem's assumptions, red boxes represent calculation modules and finally, yellow boxes are the outputs of the model.

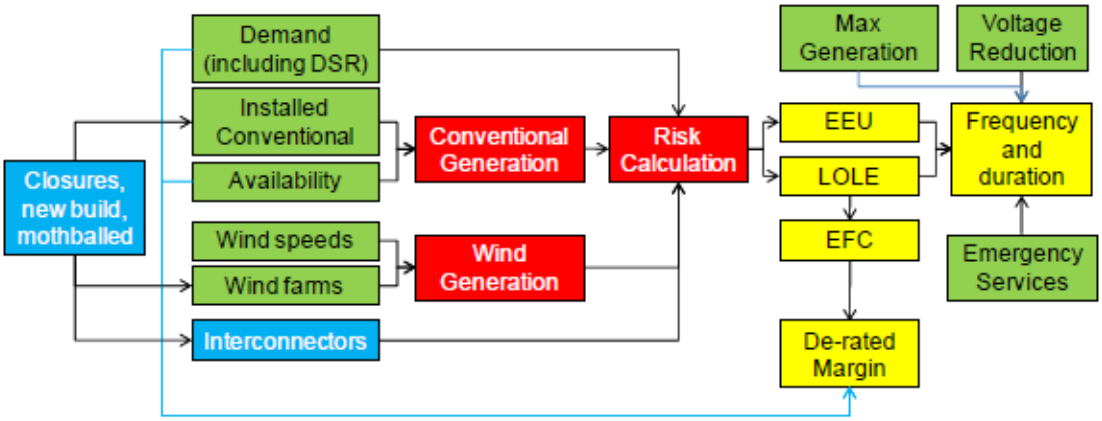


**Figure 37. [GREAT BRITAIN] Functional diagram of the modelling approach.**
**Source: *Electricity Capacity Assessment 2014: Consultation on methodology* ( [21]).**

## Demand

The distribution of demand is based on recent historical data (measured at transmission level), adjusted for each scenario based on the assumption of peak demand in each winter, considering average weather conditions' (which is called average cold spell, ACS) peak demand. The ACS peak demand has a 50 % of probability of being exceeded as a result of weather variations alone. The annual ACS conditions are defined in the Grid Code. To estimate the total demand, an estimation is needed of the embedded generation (generation connected to distribution networks except wind as this generation is assessed independently) and DSR, as they reduce the demand seen at transmission level.

Peak demand has reduced significantly since winter 2005/2006, mainly driven by the economic situation. It dropped by 1.5 GW from winter 2013/2014 in comparison with the previous year although the economic conditions were more favorable. National Grid estimates that this drop is due to a reduction in energy

consumption, a growth of DSR, an increase in generation from embedded generation and a reduction of losses on the transmission network. It is therefore assumed that peak demand will continue to reduce, mainly driven by energy efficiency and DSR in the industrial and commercial sectors. These effects will be partly cancelled by an increase in consumption due to positive economy growth.

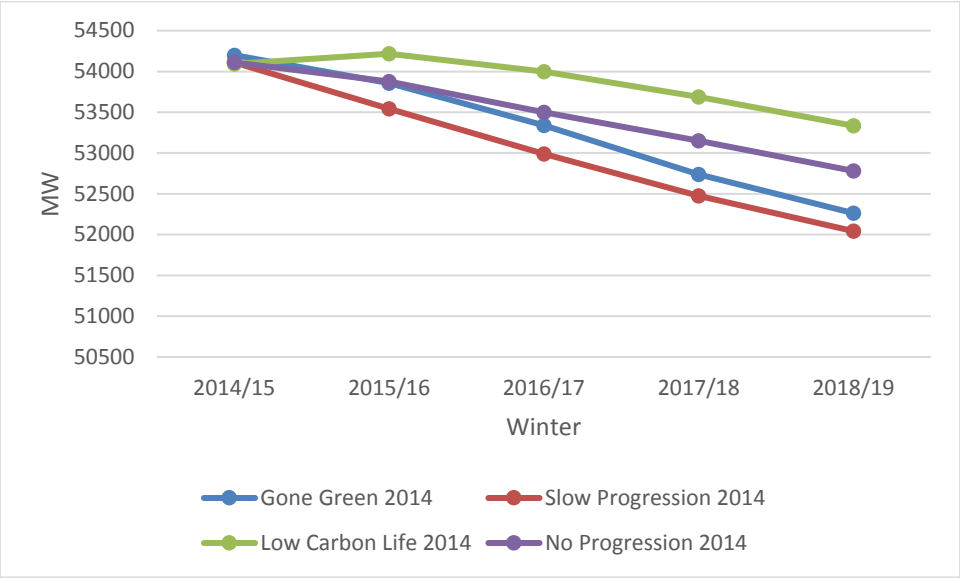


**Figure 38. [GREAT BRITAIN] Forecasted peak demand for the Future Energy Scenarios.**

National Grid reserves some amount of capacity to maintain system frequency in the event of the loss of the largest generator. As this capacity is not available under normal market operation, it is included as additional demand.

DSR and embedded generation details can be found in [22].

## Supply

Each of the FES has a generation mix based on different hypothesis, which includes different renewable energy portfolio and low carbon capacity. It takes into account expected closures, new build and mothballing of generation portfolio. The total installed capacity evolution for each of the four FES is shown in Figure 39

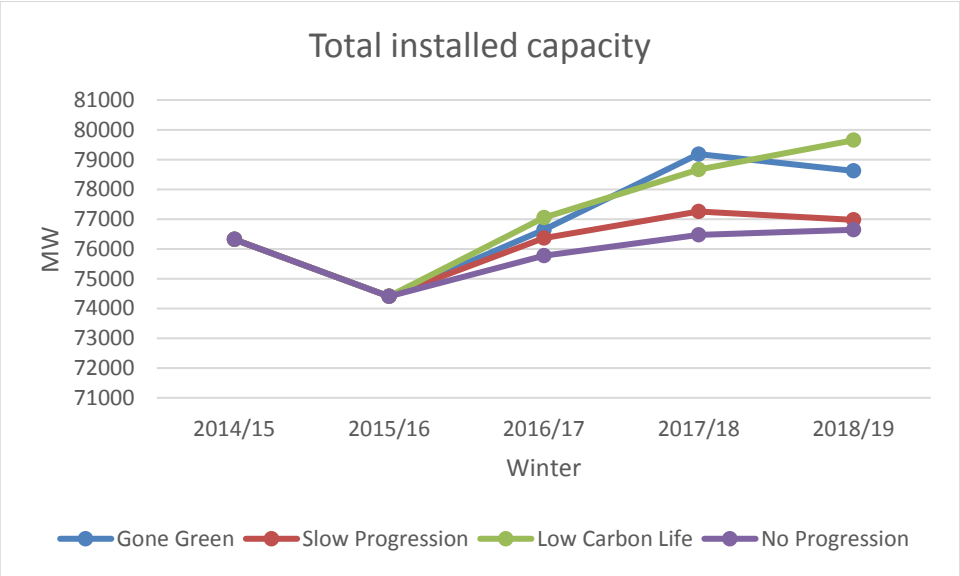


**Figure 39. [GREAT BRITAIN] Total installed capacity for each future energy scenario.**

Availability of conventional generators is estimated based on the historical data of the last seven winters, considering peak periods (from 7:00 to 19:00, Monday to Friday from December to February, on days with a peak demand greater than the 50th percentile, 90th percentile for CCGTs). Results are displayed in Table 24.

| **Generation Type** | **CCGT** | **OCGT** | **Coal** | **Nuclear** | **Hydro** | **Hydro** | **Pumped Storage** |
|---|---|---|---|---|---|---|---|
| **Mean Availability (%)** | 87 | 95 | 88 | 82 | 85 | 85 | 97 |

**Table 24. [GREAT BRITAIN] Power plant availabilities.**

Wind generation data is estimated in several steps as follows (for more details, please see [23]):

- Wind data from Nasa MERRA reanalysis dataset is used: it covers three different altitude data (2, 10 and 50 metres), from 1979 to 2012. Grid is 0.5 degree longitude and 0.75 latitude.
- It is considered transmission-connected and embedded wind.
- First, wind speed time series data is calculated for each location, interpolating the data from the historical dataset. Adjustment for hub height is done with logarithmic relationships.
- To estimate wind generation data, a power curve is constructed from nine wind farms' actual data.
- Finally, a validation process is performed.

## Scenarios

There are four different scenarios based on National Grid's four Future Energy Scenarios (FES) to represent different conditions of security of supply, affordability and sustainability. Each scenario represents an alternative possible future, considering different options of how the system might evolve (for example, the Gone Green Scenario represents a future with sustainability at the centre while the No Progression scenario represents a future similar to the current situation). As there is a security of supply target (3 hours LOLE per year from 2018/2019), the four scenarios are represented graphically, as a matrix with respect the other two axes: affordability and sustainability. It implies different assumptions in generation and demand. In addition, there is a set of sensitivities where only one input parameter is changed at a time. The following is a brief description of each FES:

1. Gone Green

- Demand will reduce until 2020 and then increases due to the high impact of Energy Efficiency programs across all sectors (residential, industrial and commercial). From 2020 there is an electrification of heating in all three sectors and a rise of electric vehicles due to prosperous economic conditions.
- Generation: Sustainability and good economic conditions will produce significant levels of Carbon Capture and Storage (CCS), renewable generation (on and offshore wind, biomass, solar and marine) and nuclear. Interconnection capacity will meet also its target.

2. Slow Progression

- Demand will remain flat until around 2030 due to high efforts in Energy Efficiency programs but with less favourable economic conditions.
- Generation: Renewable energy will increase but slower than in the Gone Green scenario. Sources of renewable sources of generation dominated by wind and solar, with contributions from nuclear and CCS.

3. Low Carbon Life

- Demand: There is an increase in industrial and commercial demand as a result of higher GDP. Energy efficiency occurs with technology improvements due to replacement of devices in the residential sector. Greater affordability results in higher take-up of heat pumps and electric vehicles.
- Generation: Sources of generation dominated by nuclear, CCS (gas and coal) and solar.

4. No Progression.

- Demand: As there is less disposable income, energy consumption is constrained, butenergy efficiency actions are also more limited, as replacement of residential appliances and lighting is more limited. Heat pumps and electric vehicles present less market share. Also, the economic conditions limit the industrial and commercial demand.
- Generation: Sources of generation dominated by gas, while renewable generation expansion is due to PV and onshore wind. Focus is on the cheapest sources of energy due to the fact that the economic conditions are less favourable, leading to reduced political emphasis on sustainability. No deployment of CCS and very limited new building programme for nuclear.

The sensitivity analysis includes a variation of one parameter at a time that can impact the risk to security of supply. The difference with the four FES is that, in this case, as only one assumption changes and the other variables will remain the same (which does not represent a realistic situation), the system is not necessarily internally consistent. The objective of the sensitivity scenarios is not to represent a plausible future scenario but to assess the impact of the uncertainty of each input parameter in isolation. Not all the sensitivities are performed with the four FES. Finally, to check the extreme values of the analysis, the worst cases are applied to the National Grid's most pessimistic FES (Low Carbon Life) and what could be better to the most optimistic scenario (Slow Progression). The sensitivies analysed the uncertainty regarding peak demand, commercial decisions by generators and interconnector flows, availability of conventional and variable generation and different weather conditions.

Sensitivities:

- Higher supply. It assumes better economic conditions for gas peak power plants and also for coal power plants. It assumes that 0.5 GW of CCGT plant remains operational in the next two winters and an additional 0.7 GW returns to the market in 2015/2016. It also assumes that 3 GW of coal plants will not be shut down.
- High supply assumes that 2GW of coal will remain due to higher profitability.
- Low Supply assumes an extra GW shut down of gas plants due to unfavourable economic conditions for gas. It represents a future where coal generation remains more economic than gas. In addition it assumes that 0.4 GW of biomass plant will be unavailable from 2014/2015 instead of 2015/2016.
- Lower supply. It assumes 1 GW of gas power plant shuts down and 0.7 GW mothballs in 2014/2015 (and come back to market in winter 2017/2018). 1.2 GW of gas power plant mothballed will be shut down definitively after the mid-decade.
- Lower demand assumes peak demand 1.5 GW lower than the National Grid's most optimistic scenario, in all winters.
- Low demand assumes peak demand 0.75 GW lower than the National Grid's most optimistic scenario, in all winters.
- High demand assumes peak demand 0.75 GW higher than the National Grid's most pessimistic scenario, in all winters.
- Higher demand assumes peak demand 1.5 GW higher than the National Grid's most pessimistic scenario, in all winters.
- Full imports. Optimistic sensitivity for interconnectors. It assumes full imports (3 GW) from mainland Europe.
- No imports. Pessimistic sensitivity for interconnectors. It assumes no imports or exports to mainland Europe (3 GW).
- Low exports assumes 0.75 GW of exports to mainland Europe.
- Low gas plant availability sensitivity assumes an availability of 82 % due to the aging of the generation fleet or due to more cycling of gas power plants.
- High gas plan availability assumes 90 % for the availability due to an increase of their availability at peak time to profit from higher prices periods.

- Low wind availability. It assumes a reduction of wind availability at demand periods greater than 92 % of the ACS peak demand. The maximum reduction is assumed to be 50 % for the demand levels higher than 102 % of ACS peak demand.
- Warm winter. Demand is assessed with historical data from winter 2006/2007 which was the warmest winter in the last nine winters (period used to estimate the average winter weather conditions).
- Cold winter. Demand is assess with historical data from winter 2010/2011 which was the coldest winter in the last nine winters (period used to estimate the average winter weather conditions).

### Consideration of reserves

Capacity reserve to maintain system frequency (largest in feed loss) is considered as an additional demand. National Grid would curtail demand before using this reserve.

### Interconnectors

National Grid estimates capacity levels and flows between GB and its interconnected markets in winter. It is based on analysis of historical flows since winter 2005/2006, feedback from industry and the estimation of the evolution of the interconnected markets. Export flows and import flows are treated as demand and generation respectively. Installed capacity is 3.8 GW for all the FES and the five winters. In the FES, National Grid assumes that exports to Ireland are fully compensated by imports from mainland Europe. Interconnection capacity to mainland Europe and Ireland is 3 and 0.75 GW respectively.

### Indicators

Five indicators are calculated to estimate the security of supply, although the target is established only for LOLE. The indicators are the following:

- LOLE. It is the average number of hours per year in which demand is greater than supply with no intervention from the TSO. This means that it is not the same as the amount of hours of customer disconnections.
- De-rated capacity margin. The average excess of available generation capacity over peak demand. It can be expressed in percentage terms or as a capacity value. The de-rated margin is calculated with the following equation:

$$de-rated\ margin = \frac{average\ available\ supply-(ACS\ peak\ demand+Net\ Exports+LIF)}{(ACS\ peak\ demand+Net\ Exports+LIF)} \qquad \text{Eq. 2}$$

  where LIF is the largest infeed loss reserve requirement.
- Expected Energy Unserved. It is the expected amount of electricity demand that would not be served due to loss of load.
- 1 in n probability of controlled disconnections. It provides a view of the likelihood of experiencing controlled disconnections of customers due to a large shortfall. It is based on judgments on how the system would be operated when supply does not meet demand, and the order and size of mitigation actions taken by National Grid as TSO.
- Equivalent Firm Capacity of wind. It is the equivalent amount of firm capacity required to maintain the same security of supply level measured by LOLE.

LOLE and EEU are calculated, as was explained in the Methodology subsection, with the convolution of the distribution of wind power, available generation and winter demand. The result of the convolution is the probability function of the surplus. The LOLE and EEU are estimated from the part of the surplus distribution where the supply is lower than demand.

De-rated margin is estimated subtracting, from the typical available capacity, the adjusted peak demand.

### Results

Figure 40 shows the results in terms of LOLE for the four central scenarios (Gone Green, Slow Progression, Low Carbon Life and No Progression) and the different sensitivity scenarios. As the sensitivies assume an

extreme value for one of the input parameters, the results are always or better or worse than the central scenario results. In all cases the worst result is for the winter 2015/2016. LOLE represents the expected number of hours in a year where the TSO will need to take actions that go beyond normal operations but it does not mean customer disconnections.

Results regarding de-rated margins are shown in Figure 41. It is worth mentioning that the evolution of de-rated capacities runs counter to LOLE (when one increases, the other decreases) due to the fact that they represent opposite concepts (supply margin over demand and probability of demand be greater than supply, respectively).

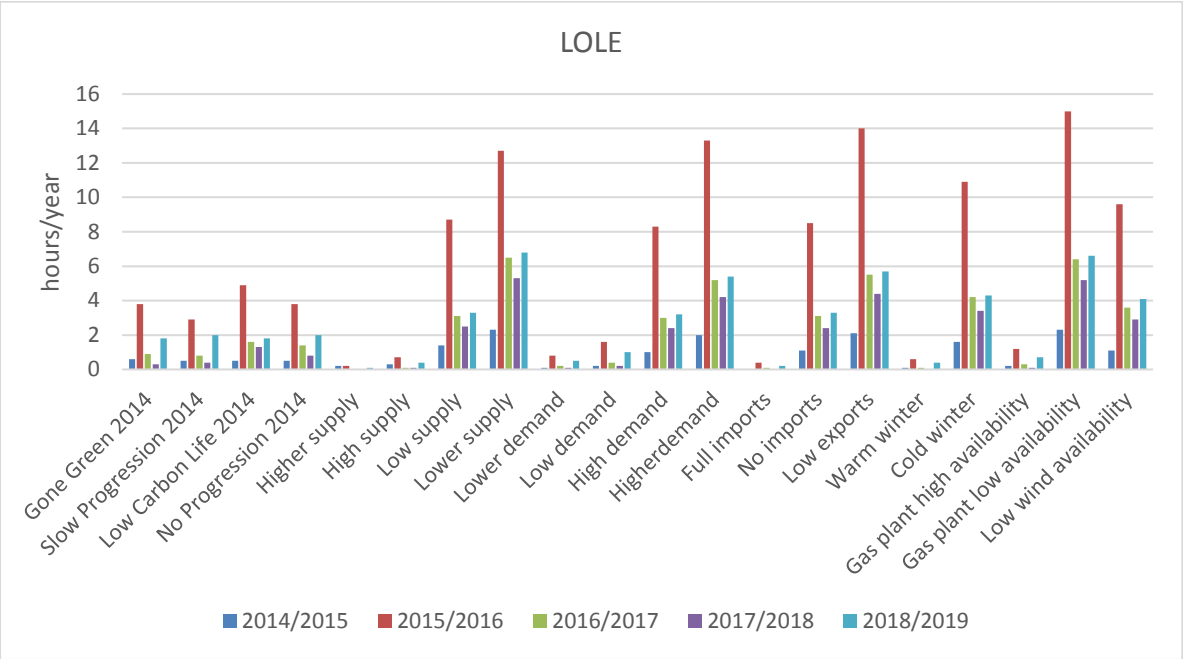


**Figure 40. [GREAT BRITAIN] Loss of load expectation by scenario and sensitivity.**

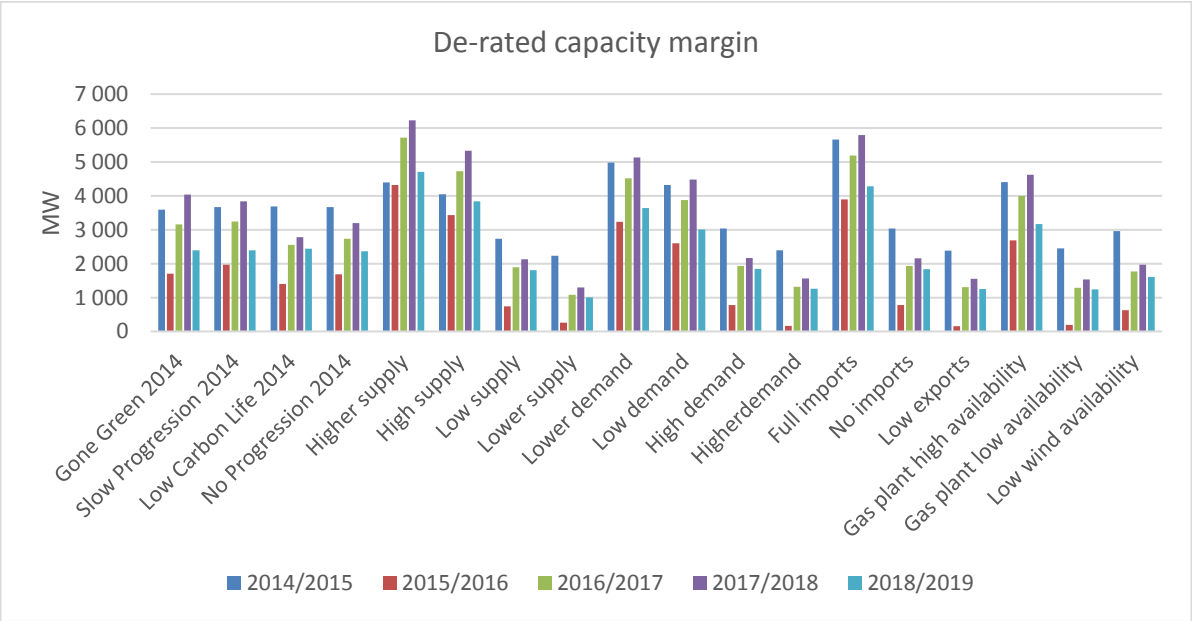


**Figure 41. [GREAT BRITAIN] De-rated capacity margin by scenario and sensitivity.**

Finally, Figure 42 represents the wind equivalent firm capacity as a proportion of installed capacity.

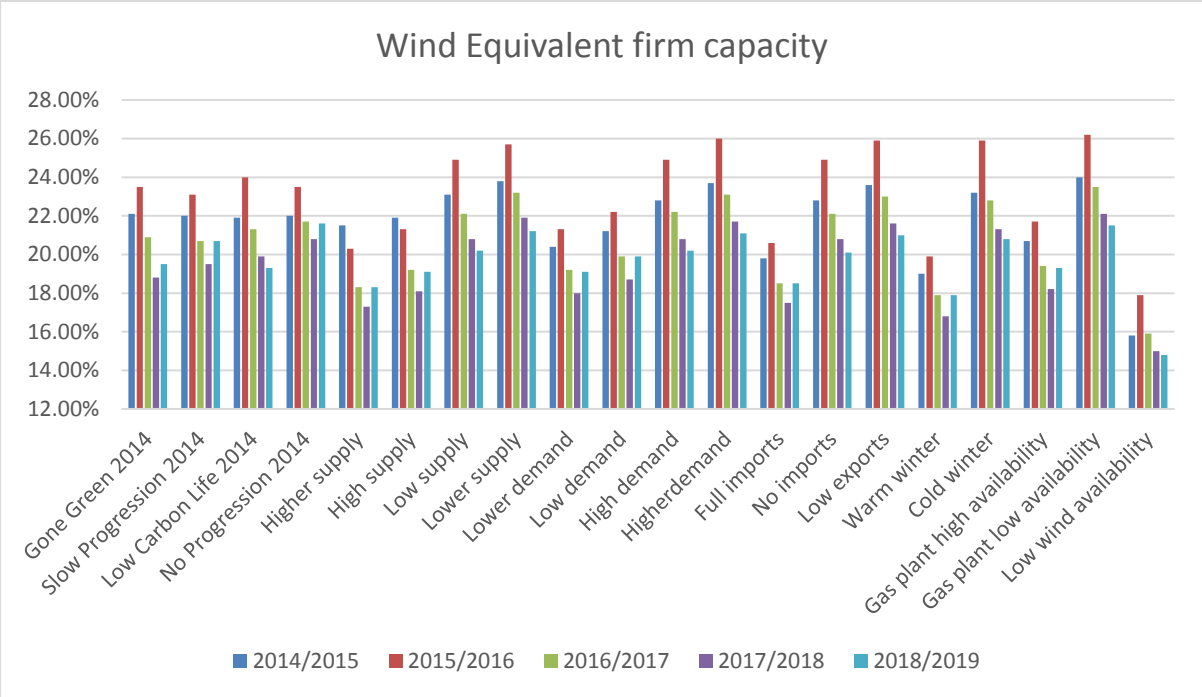


**Figure 42. [GREAT BRITAIN] Wind equivalent firm capacity by scenario and sensitivity as a proportion of installed wind (%).**

### Remarks

Electricity Capacity assessments will no longer be published as Great Britain puts in place a Capacity Market to ensure the 3 hours/year LOLE's target value. Four scenarios are considered with a full range of sensitivities to cope with the uncertainty in the input parameters of the model. Something worth mentioning is that the assessment is done using a non-sequential Monte Carlo model, although it is remarked, in the methodology document (see [21]), that it may become less valid over time as the penetration of intermittent generation increases and the DSR initiatives grow. Also, as the flexibility assessment is out of the scope of the report, they considered a sequential model unnecessary.

## 2.8 ENTSO-E

Article 8 of Council Regulation (EC) No 714/2009 ( [24]) establishes that ENTSO-E shall adopt annual summer and winter generation adequacy outlooks and a long-term European generation adequacy outlook every 2 years. This latter outlook shall cover the overall adequacy of the electrical system to supply current and projected demands for the next 5 years as well as for the period between 5 and 15 years. ENTSO-E is performing this long-term European generation adequacy outlook every year (so-called, Scenario Outlook and Adequacy Forecast, SO&AF), with a time horizon of 15 years until SO&AF2014 and 10 years in SO&AF2015. The Regulation also establishes that this European Generation adequacy outlook shall build on national generation adequacy outlooks prepared by each individual TSO, which implicitly is constraining the approach to bottom-up scenarios. This report is focused on this long-term generation adequacy assessment and not on the short-term winter and summer outlooks.

### Methodology

In October 2014, ENTSO-E published a target methodology for the Adequacy Assessment ( [25]). The aim is to move from the deterministic power balance assessment to a sequential Monte Carlo probabilistic methodology. This evolution will be done progressively; it is expected to be completely implemented by 2018. The first steps towards this new methodology were done in the SO&AF 2015. For the sake of clarity, the review of ENTSO-E methodologies covers the following elements:

- Review of the traditional methodology for the long-term generation adequacy assessment.

- Review of new elements in SO&AF 2015.

The target methodology will be explained in the next section of this report, with the Pentalateral Energy Forum generation adequacy assessment, as they have applied ENTSO-E target methodology in their assessment.

Traditional assessment

ENTSO-E has been assessing the adequacy based on a deterministic power balance at two particular points of time (third Wednesday in January at 19:00 and third Wednesday in July at 11:00). The approach can be seen graphically in Figure 43 and the details of the methodology are described in [26]. The main objectives of this analysis are: (1) to check if the remaining capacity (RC) is a non-negative value in the power system analysed (this means that there is enough available generation capacity under normal conditions). If this value is negative, the power system is short in available generation capacity under normal conditions. It does not mean that there would be a shortage as energy can be imported. (2) To compare the remaining capacity with the Adequacy Reference Margin (ARM). If RC ≥ ARM then the security of supply of the system is likely to be guaranteed in most of the situations. Otherwise, the system will rely on imports at moments of seasonal peak demand or severe conditions.

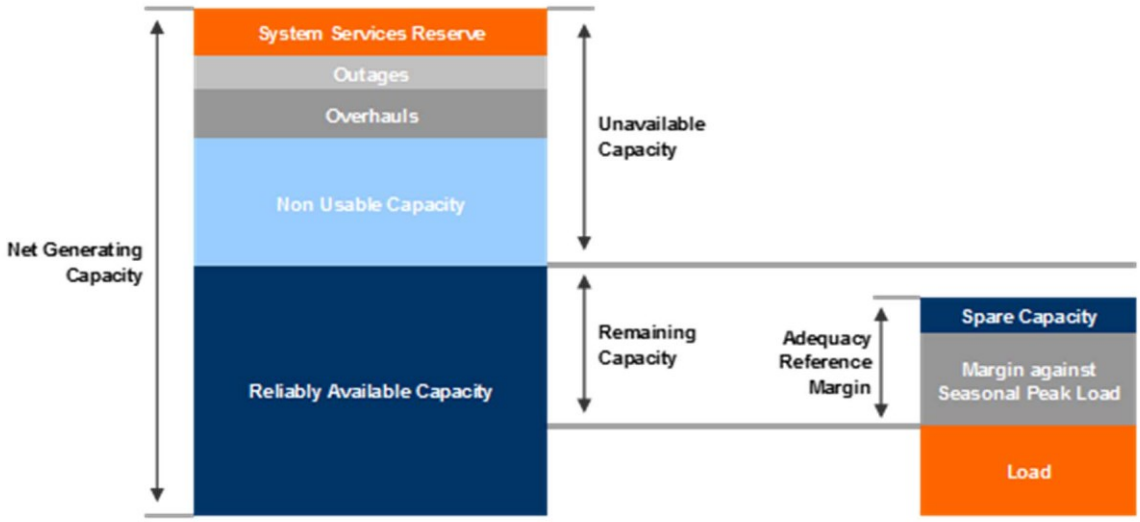


**Figure 43. [ENTSO-E] Schematic representation of the power balance for the adequacy assessment. Source: *SO&AF 2014.***

The main equations in the power balance are:

$$RAC = NGC - UC \qquad \text{Eq. 3}$$

where RAC is the Reliably Available Capacity, NGC is the Net Generating Capacity and UC is the Unavailable Capacity. Unavailable Capacity is composed of four terms: System Services Reserve, Outages, Overhauls and Non-usable Capacity (see Figure 43). Wind and solar generation are considered as Non-usable Capacity.

The Remaining Capacity is estimated as

$$RC = RAC - Load \qquad \text{Eq. 4}$$

Finally, the Adequacy Reference Margin is

$$ARM = SC + MaSPL \qquad \text{Eq. 5}$$

where SC is the Spare Capacity and MaSPL is the Margin against Seasonal Peak Load. The Spare Capacity is an estimation of the required capacity to add to the System Services Reserves to cope with unforeseen extreme conditions. The MaSPL is considered as the peak load does not necessarily correspond with the reference time in which the power balance is performed.

The analysis is performed under normal conditions which means that the demand is estimated considering average temperatures.

SO&AF 2015

As was mentioned before, SO&AF 2015 presents some differences with the previous versions although it is still based on the deterministic approach. Some of these differences are the following:

- The assessment is performed with a time horizon of 10 years instead of 15 years. The time horizon is a trade-off between the uncertainties in models and inputs (uncertainty increases over the time horizon) and the time required to plan and make future investments.
- In order to provide more insights, it presents a monthly power balance. The previous ones only provided figures for two reference points: the third Wednesday of January at 19:00 and the third Wednesday of July at 11:00 (see [27]).
- A common reference point in time is used for the pan-European monthly assessment but national assessments are based on the reference time and the national monthly peak load time.
- The pan-European adequacy assessment provides information about the increase of the national adequacy levels by means of imports. To do that, a constrained linear optimization problem is performed to minimise the deficit in power balance at the pan-European level. More details are not provided (equations). The results are presented graphically.
- Wind and solar energy is not considered Non-usable Capacity by default. Instead of that, an estimation of their load factor is estimated with a pan-European Climate Database
- It shows the analysis of residual load as an initial understanding of future flexibility needs through the assessment of the maximum ramping requirements and the calculation of some indicators regarding renewable energy penetration in the system. This analysis is performed with 1-hour resolution as a first step.

## Demand

SO&AF2015 demand is based on the most conservative information collected from TSOs. Previous versions assess the adequacy with more than one demand scenario (for example, SO&AF2014 used the same four visions as the Ten Year Network Development Plan (TYNDP).

## Supply

The analysis is based on two different scenarios for generation (Scenario A and B). Scenario A (or conservative scenario) considers only new capacity if it is considered as certain and regarding the decommissioning, it considers the official notifications but also additional criteria as for example, technical lifetime of the generators. Scenario B (or best estimated scenario) considers as new install capacity the same as scenario A but also other commissioning generators that can be considered as reasonable credible. Regarding decommissioning, it only considers official communications. The difference between the two generation scenarios are shown in Table 25.

| Net Generation Capacity (GW) | 2016 | 2020 | 2025 |
|---|---|---|---|
| Conservative Scenario (Scenario A) | 1 012 | 1 051 | 1 052 |
| Best Estimate Scenario (Scenario B) | 1 021 | 1 086 | 1 167 |

**Table 25. [ENTSO-E] Net Generation Capacity forecast in January at 19:00.**

SO&AF2015 is the first time ENTSO-E is assessing the load factor of wind and solar energy. The non-usable wind or solar capacity at a particular point in time is proportional to (1 – LF) where LF is the load factor and it is estimated as the 10th percentile of the monthly load factor at that particular point in time, with the 14 climate years of ENTSO-E's pan-European Climate Database for each country. This refers only to the power balance assessment at reference or peak demand moments. For the flexibility analysis, the full 14 climatic years PECD time series are used with hourly resolution.

## Scenarios

As was mentioned previously, only one scenario for demand is combined with two different scenarios for generation which cover the years 2016, 2020 and 2025.

## Consideration of reserves

In the deterministic power balance, system services reserve are considered as Unavailable Capacity. System Service Reserve to cope with unforeseen extreme conditions are considered as spare capacity.

## Interconnectors

Import and export capacities for each country are reported by the different TSOs.

## Indicators

The generation adequacy is assessed through the Reliability Available Capacity (RAC), the Remaining Capacity (RC) and the Adequacy Reference Margin (ARM) as was explaining in the methodology sub-section (see Eq. 2, Eq. 3 and Eq. 4 respectively).

In SO&AF2015 new indicators are estimated to analyse the impact of renewable energy generation in adequacy:

- RLPI (RES Load Penetration Index). It is the maximum hourly coverage of Load by non-dispatchable renewables energy generation (wind and solar):

$$\mathbf{RLPI} = \mathbf{max}\left(\frac{\mathbf{W_i+S_i}}{\mathbf{L_i}}\right) \text{ for i=1,2,3...,8760} \qquad \text{Eq. 6}$$

  where $W_i$ is the wind energy generation at time i, $S_i$ is the solar generation at time i and $L_i$ is the demand at time i.

- REPI (RES Energy Penetration Index) It is the average value of demand covered by wind and solar generation.

$$\mathbf{REPI} = \frac{\mathbf{W_{annual}+S_{annual}}}{\mathbf{E_{annual}}} = \frac{\sum_{i=1}^{8760}(\mathbf{W_i+S_i})}{\sum_{i=1}^{8760}\mathbf{L_i}} \qquad \text{Eq. 7}$$

- RCR (RES Curtailment Risk):

$$\mathbf{RCR} = \frac{\mathbf{number\ of\ hours\ in\ the\ year\ with\ RL_i<0}}{\mathbf{8760}} \qquad \text{Eq. 8}$$

  where RL residual load is estimated as

$$\mathbf{RL(h) = L(h) - W(h) - S(h) - must\_run} \qquad \text{Eq. 9}$$

  L(h) is the demand at time h, W(h) is the wind generation and S(h) the PV generation, and must-run generation is the generation needed due to several factors (network constrains, system services, etc.).

The assessment of flexibility needs is done with the estimation of the maximum residual load ramp events.

## Results

### National Assessments

A national upward generation adequacy assessment (a power balance) is performed considering two time reference points for each month:

- Third Wednesday at 19:00 (11:00 in summer).
- Peak load time.

A descriptive graph like Figure 44 is presented for each country. For each month, the figure displays the worst power balance between the reference point time (light orange color for Scenario A and light blue for Scenario

B) and the national peak load time (dark light orange color for Scenario A and dark blue for Scenario B). Logically, peak time is the worst situation in most of the cases. A second information provided in the figure is the import and export capacity (green and yellow colors respectively). For those countries that have reported higher import/export capacity for Scenario B than for Scenario A, this difference is highlighted in dark green and yellow colors. When the power balance is positive, a comparison between it and the export capacity can be made. When the power balance is negative, the country shall rely on imports for guarantee the supply, so a comparison between the power deficits and the import capacity is of utmost importance. The import and export capacities are not the interconnection capacities between countries and these values are not symmetric as they are estimated considering the power flows in different network situations and other particular characteristics of each country power system.

It is worth mentioning that the power balance is performed differently for the two periods of time:

- For the reference point the power balance is estimated as Remaining Capacity minus Spare Capacity.
- For the peak load time, the power balance is the Remaining Capacity (with PECD solar and wind monthly load factor at the daily hour of expected peak load in each country) minus Adequacy Reference Margin which is Spare Capacity plus Margin Against Monthly Peak Load.

Renewable Energy Indices

The results are presented in Figure 45, Figure 46 and Figure 47. Regarding the RES load penetration index (RLPI) which is the maximum hourly coverage of load by RES, 22 countries/regions are expected to have a value higher than 50 % by 2025, with 8 of them reaching full load penetration level (Denmark, Germany, Great Britain, Greece, Ireland, Northern Ireland, the Netherlands and Portugal. Regarding the average penetration level, REPI, maximum values are expected in Denmark, reaching more than 50 % in 2025. ENTSO-E establishes in the SO&AF2015 that RES curtailment risk greater than 0.5 means a significant penetration level of RES generation in the power balance. All the countries with full RES load penetration (RLPI > 100 %) will be exposure to some risk for RES curtailment with the highest expected value in Northern Ireland. It is worth mentioning that the calculated values of RCR do not take into account must-run generation which increase the risk of curtailment.

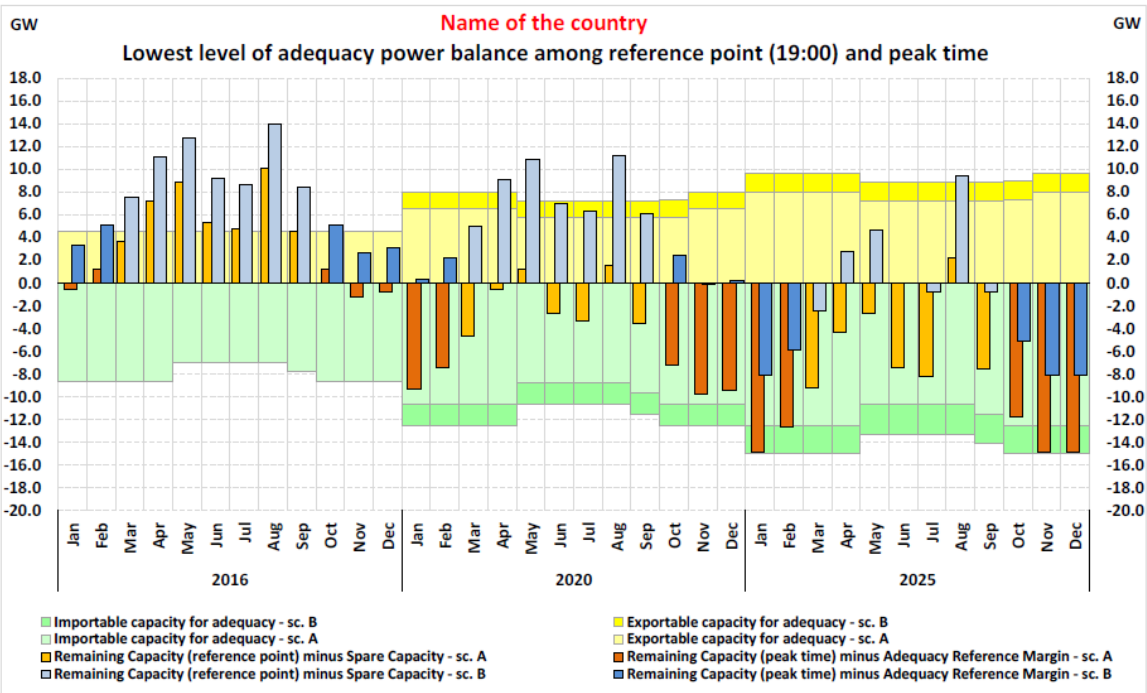


**Figure 44. [ENTSO-E] National upward generation adequacy.**
**Source: SO&AF 2015.**

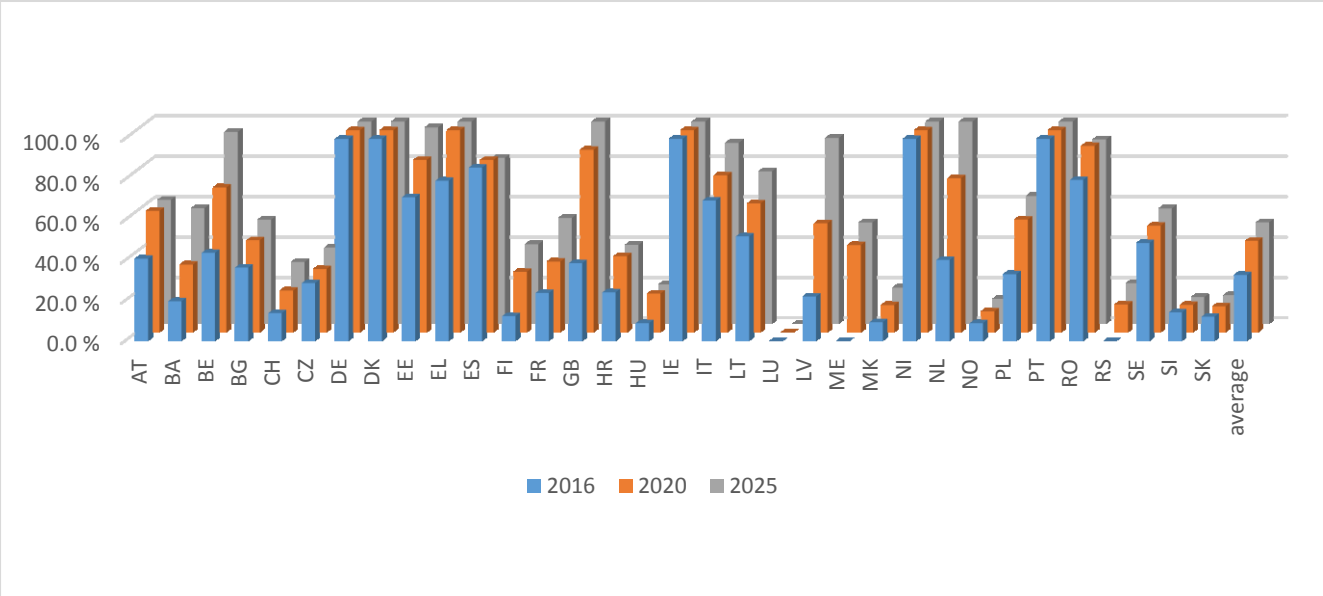


**Figure 45. [ENTSO-E] RES load penetration index (RLPI) for all ENTSO-E countries referring to years 2016, 2020 and 2025 considering Scenario B. Values shown as 100 % are reported in SO&AF2015 as >100 %.**

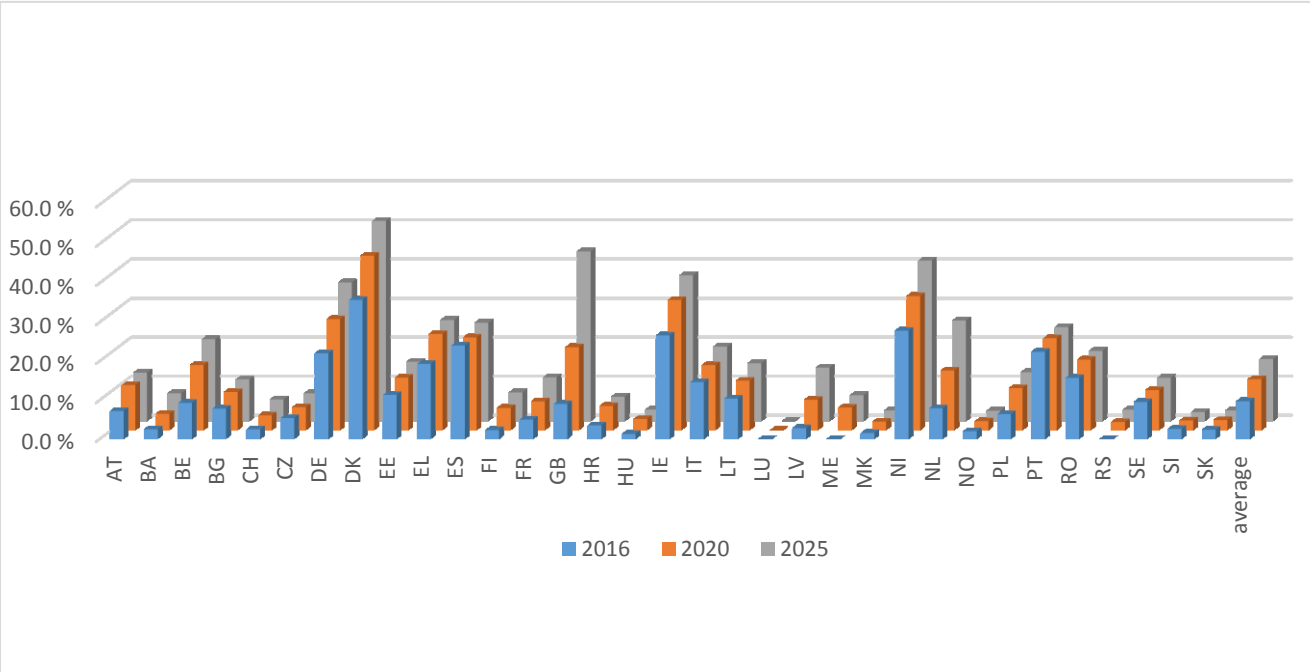


**Figure 46. [ENTSO-E] RES Energy Penetration index (REPI) for all ENTSO-E countries referring to years 2016, 2020 and 2025 considering Scenario B.**

First steps towards probabilistic assessments:

For each country the following graphs are presented:

- Normal and real daily temperatures. ENTSO-E performs the generation adequacy study considering normal conditions. This normal condition means, regarding load, that demand is considered at average temperatures (30 years). As demand is sensible to temperature (due to heating and air conditioning), a graph with the normal (average) temperature and the real daily temperatures is presented (see Figure 48). The real daily temperatures are estimated with the PECD climatic years and they are population-weighted average.

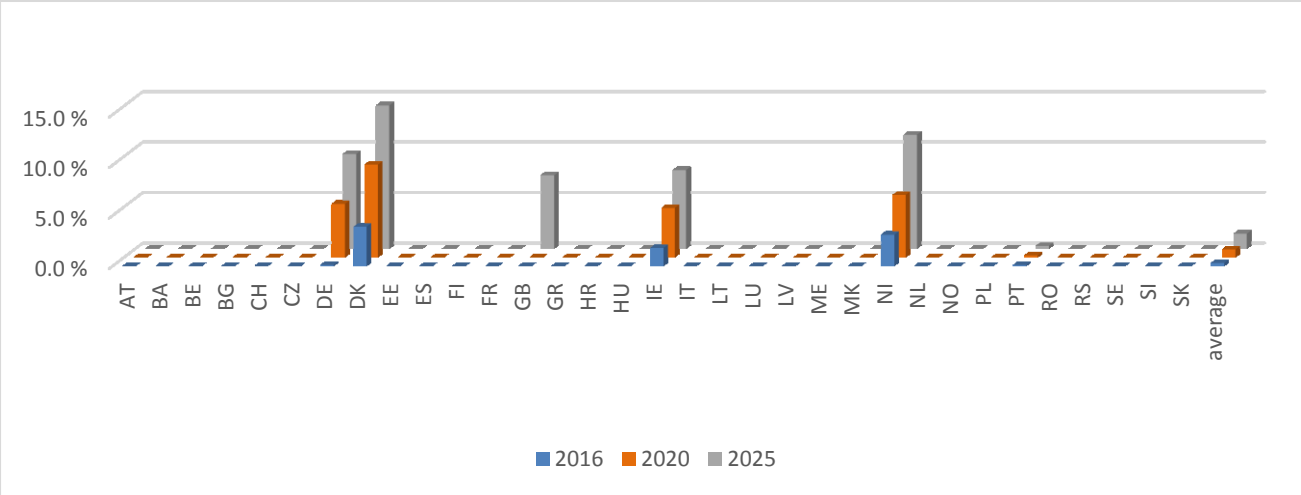


**Figure 47. [ENTSO-E] RES curtailment risk (RCR) for all ENTSO-E countries referring to years 2016, 2020 and 2025 in Scenario B.**

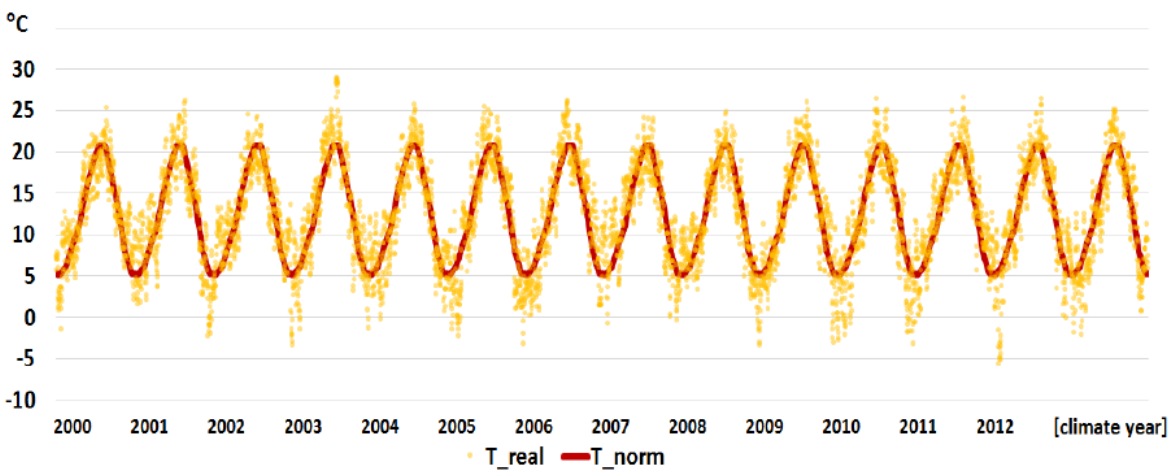


**Figure 48. [ENTSO-E] Example of average and actual daily temperature.**

**Source: *SO&AF2015 [ENTSO-E].***

- Distribution of RES penetration including must-run. A graph with the distribution of 1-RL (where RL is the residual load in relative terms) is presented. Values above 100% indicate the need for curtailment and/or storage and/or export as RES generation plus must-run exceeds the country consumption. See Figure 49.
- Distribution of hourly RES ramps in % of load. This figure shows the distribution of hourly RES ramps to estimate the change of RES in-feed from one hour to the following (these changes shall be cover by other means, typically conventional generators). RES ramps are estimated in relative values of the load. See Figure 50.
- Hourly behavior of RL. This chromatic graph shows the hourly value of the residual load (in relative terms and in the form of 1-RL), see Figure 51. This figure presents two vertical axis: the left side is the week of the year, and the right side is 1-RL presented as a color-coded value. There are also two horizontal axis: the bottom one is the hour of the day and on top it is shown the day of the week (it is important to see the different risk considering working or weekend days, as the last ones have low demand values and for each day to see the peak and valley demand periods of time). With this figure, temporal cycle patterns can be seen graphically. For example, daily cycles can be seen clearly in countries with significant PV penetration.

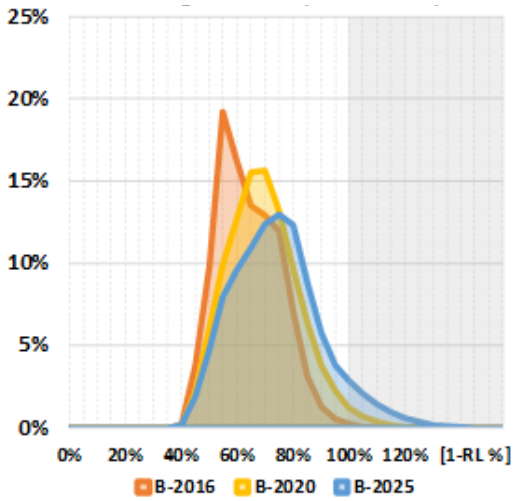


Figure 49. [ENTSO-E] Distribution of RES penetration including must run (in % of load). Scenario B.

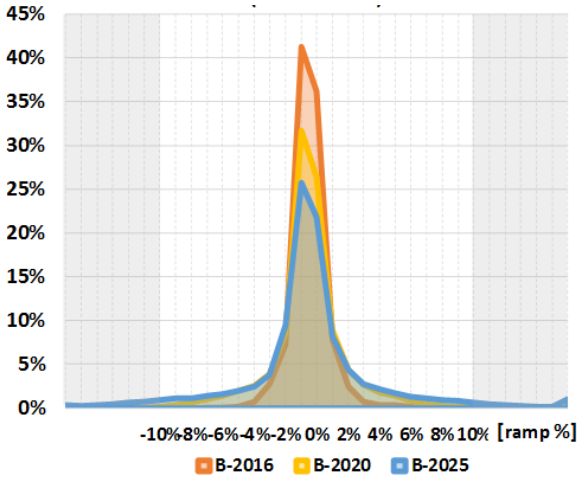


Figure 50. [ENTSO-E] Statistical distribution of hourly RES generation ramps in values relative to the load. Scenario B.

Source: *SO&AF2015* [ENTSO-E].

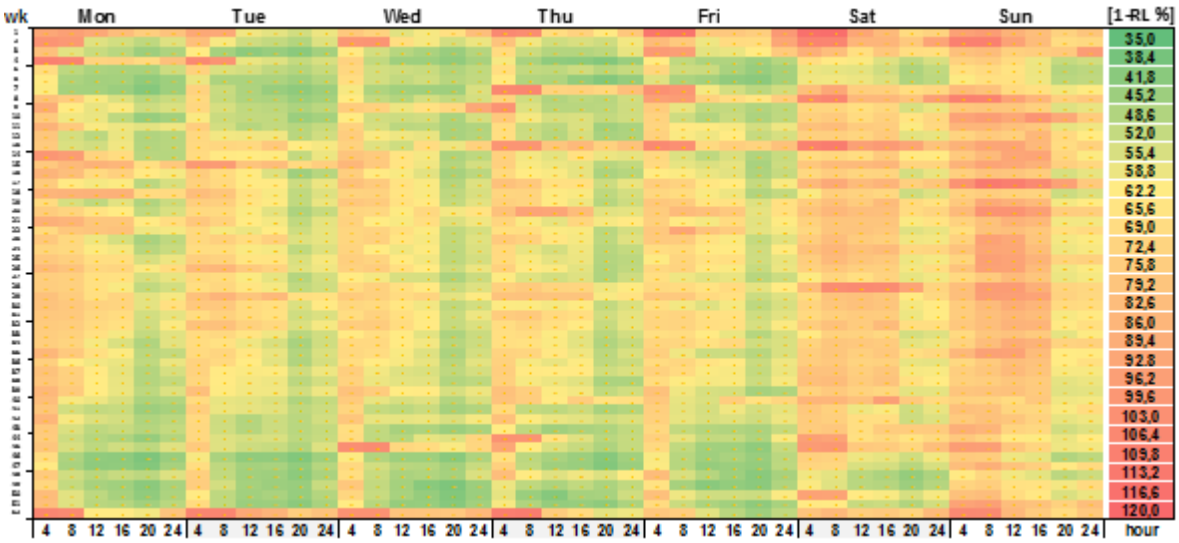


Figure 51. [ENTSO-E] Hourly value of residual load. Scenario B year 2020 with 2012 climate conditions.

Source: *SO&AF2015* [ENTSO-E].

## Pan-European assessments

The objective is to complement national assessments and to highlight adequacy contribution of interconnectors.

The monthly reference point (third Wednesday of the month at 19:00) is chosen for the optimisation problem. Results are presented graphically. If a country will not need to import power to maintain adequacy, then is coded with green color, otherwise with a yellow color. See Figure 52.

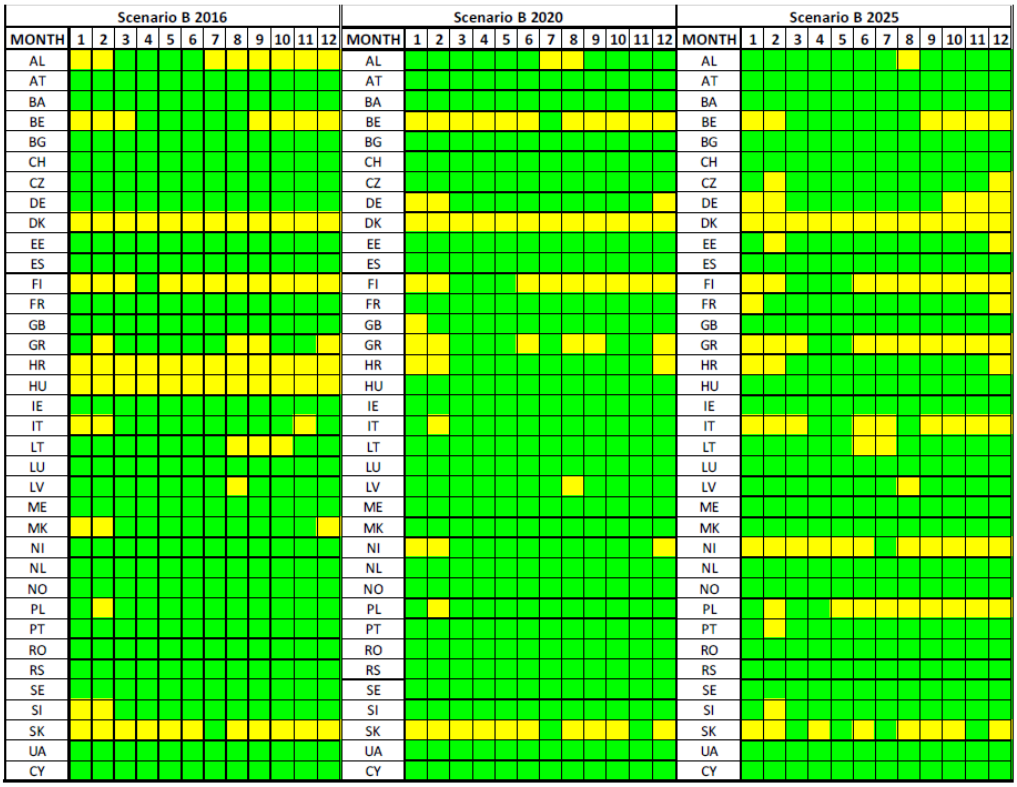


**Figure 52. [ENTSO-E] Interconnection contribution to Member States adequacy. Scenario B. Source: *SO&AF2015* [ENTSO-E].**

## 2.9 Pentalateral Energy Forum

The Pentalateral Energy Forum is the framework for regional cooperation in Central Western Europe (Austria, Belgium, France, Germany, Luxemburg, the Netherlands and Switzerland) towards improved electricity market integration and security of supply. In the Political Declaration of the Pentalateral Energy Forum (2013), the Ministers requested the TSOs to deliver an enhanced pentalateral adequacy assessment.

The last report was published in 2015: Generation Adequacy Assessment [28].

### Methodology

Probabilistic and chronological approach with an hourly resolution for the year 2015/2016 and the year 2020/2021.

The methodology is similar to the ones already implemented in Belgium and France and similar to the target methodology for ENTSO-E. Probability model and regional perimeter.

The study assesses adequacy in two time horizons: 2015 and 2020 winters.

Two tools are used alongside each other: one probabilistic — ANTARES — and one deterministic — AMPRION. The advantages of using several tools at the same time is to debug inputs and models so the results can be seen as consistent.

A market model is the base of the assessment. It assumes perfect competition and the mathematical problem is formulated as a Mixed-Integer Linear Programming (MILP) problem. To apply this type of model at regional scale, the resolution is performed in two steps to reduce the computation time: the first step performs a yearly run of the model with a weekly time step. Second, 52 weekly runs are performed with 1-hour time step. Also, in order to avoid infeasible solutions, very often the constrains are modelled as 'soft' constraints which means that they could be violated but at the expense of a high penalty. To implement a market tool for adequacy studies, a large number of simulations with random draws of the inputs shall be

performed. To saving computation time, other simplifications are considered as reducing integer variables of the problem (for example the on/off decisions), some ramping constraints, etc.

In order to reproduce the interconnected system in a proper way, neighbouring countries are modelled. Three different levels of detail are provided:

- Small first neighbours. Data is estimated based on SO&AF2013, considering Remaining Capacities (RC) and Adequacy Reference Margins (ARM).
- Big or 'influential' neighbouring countries (Spain, Italy and Great Britain). Installed capacities for each technology are taken from SO&AF2013 and modelled with the Pan-European Market Modelling Data Base (PEMMDB). To estimate the hourly demand for these countries a simple ratio with ENTSO-E EU2020 Scenario is performed.
- Second neighbours (Greece, Portugal, Ireland and Northern Ireland) are modelled as the small first neighbours.

## Demand

The first characteristic to preserve is the correlation of demand among the different countries.

Demand is estimated as follows:

- A normalised load profile is estimated. Normal temperature is estimated as the average value of the PECD values.
- A temperature sensitivity model was developed and is added to the load profiles. The objective is to estimate, for each country, the thermo-sensitivity of demand based on historical load data and the PECD. The model estimates the following parameters:
- Gradient (MW/°C). Increase of power demand for each 1°C drop in ambient temperature.
- Threshold temperature. It is the temperature below which demand becomes sensitive to weather condition.
- Smoothing of the outdoor temperatures.

With all of these elements, load time series under several climatic conditions are built.

Demand Side Response. Although it is a very relevant matter for generation adequacy assessment, the variety of different contracts in the different countries, makes its modelling a difficult task, so some simplifications were done.

## Supply

For the short-term analysis (from 1 October 2015 to 30 September 2016), ENTSO-E Scenario A given in SO&AF2013 is considered, except RES generation which is modified according to TSOs' best estimation. This is a conservative scenario where the commissioning of new power plants are considered only if they are confirmed. The same for decommissioning. Fuel and $CO_2$ prices are taken from 'Current Policies Scenario' in *IEA World Energy Outlook 2013*.

For the mid-term analysis (from 1 October 2020 to 30 September 2021), a PLEF scenario 2020 is estimated considering the same approach as the previous one.

Supply model assumptions are as follows:

- Hydro modelling. Hydro capacity accounts for 16% of the total installed capacity in the region, which ranks the second highest, only after gas. This is one of the most challenging parts due to the complexity of modelling hydro production systems. Correlated and synchronised hydro data are considered for Switzerland, Austria, France and Germany. Reservoir inflow, river flow and reservoir level are given as inputs to the model, and treated as constraints:
    - Natural reservoir inflow per week is predefined according to different hydrological years (wet, normal and dry). Maximum and minimum pumping and turbining capacities are additional optimisation constraints.

    - For run-of-river the weekly energy production is predefined.
    - Regarding reservoir levels, the starting and ending levels of the reservoir's annual stores are provided to the model. These values are estimated by interpolation or from equally dividing monthly values.
    - Wet, dry, and normal profiles are based on the years 1999, 2011 and 2008 respectively. The probability of occurrence of each of them is 10%, 10% and 80% respectively. Each profile contains weekly values of RoR, reservoir production (storage, pumped storage and swell power plants) and natural inflow for reservoir.
    - Models are based on water quantity analysis of historical data instead of production data, as different years have different installed capacities.
- Outages and maintenance of thermal dispatchable units. Reference values from ENTSOE are taken, which depend on the type of thermal unit, fuel and age. The 22 different categories defined in the guidelines for the Pan-European Market Modelling Data Base (PEMMDB).
- Wind and solar generation time series are estimated considering correlated wind, radiation and temperature, to preserve the correlation of demand, wind and solar generation. The model assumes that wind and solar generation will be used in a similar way than in the past.
- Other RES and non-RES generation considered as non-dispatchable are simulated as inflexible sources which means that they are not price-driven. They are, among others, tidal, wave, geothermal, biomass and waste generation and CHP.

## Scenarios

The assessment is performed considering the following scenarios:

- Reserves.
- Considering operational and strategic reserves as available for adequacy purposes (so, they are not removed from supply capacity).
- Operational reserves and strategic reserves are taken away from supply. This is referred to as Base Case Study.
- Extreme climate conditions. 2001 to 2011 years are considered as 'normal years'. However, 2012 is considered as extreme due to the persistent cold spell.
- Isolated case. NTC values are considered zero, so all the PLEF countries are electrically isolated. In this way, the importance of interconnectors for adequacy can be assessed.

## Consideration of reserves

Two types of reserves are considered:

- Operational reserves: primary, secondary and tertiary reserves in all the PLEF countries.
- Strategic reserves. They are considered in Belgium and Germany and they are used only in case of necessity.

## Interconnectors

Two different BTC values (winter and summer) are considered. BTC values are the expected capacity available for the market on an interconnection between two areas. Every country can define constrains on simultaneous import and export capacities to not overestimate these values.

## Indicators

The following indicators are calculated:

- LOLE (hours/year).
- LOLP (%).

- EENS. It is expressed in two different ways: The absolute value (GWh/year) and the relative EENS per country in order to facilitate the comparison among countries. It is the ration between EENS and the average annual consumption.

Belgium and France have established 3 hours/year as target value for LOLE and the Netherlands have established 4 hours/year. There is no target for the region as a whole.

## Results

LOLE average values for the different countries and the PLEF region are shown in Figure 53. The following scenarios are represented:

- Isolated means no interconnected system, with strategic and operational reserves.
- Reserves means interconnected system, with strategic and operational reserves.
- Central means interconnected system with strategic reserves and without operational reserves. This is the base case for the PLEF TSOs.
- No reserves means interconnected system without strategic and operational reserves.

Under the following conditions:

- 2015 normal means short-term assessment with normal weather conditions (2001-2011 climate data).
- 2015 severe means short-term assessment with severe weather conditions (2012 climate data).
- 2020 normal means mid-term assessment with normal weather conditions (2001-2011 climate data).
- 2020 severe means mid-term assessment with severe weather conditions (2012 climate data).

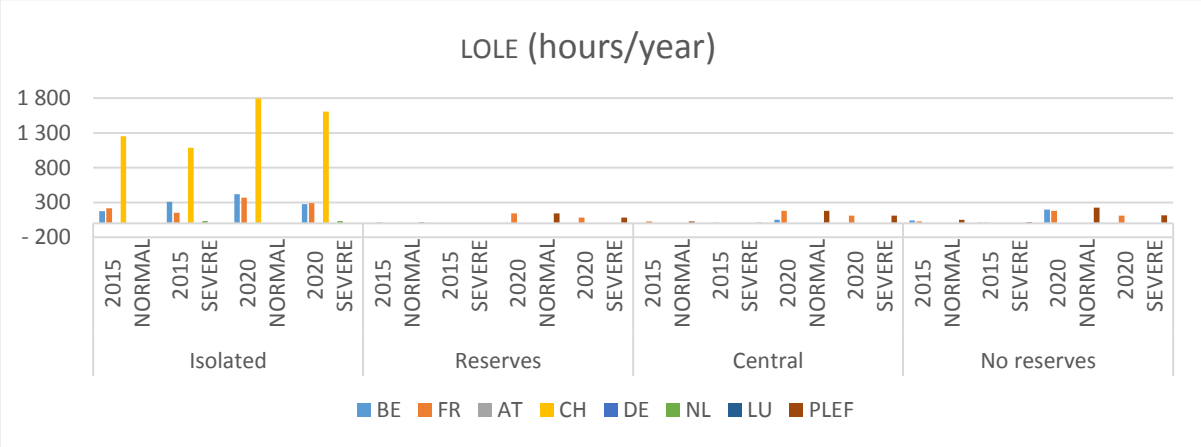


**Figure 53. [PLEF] Average LOLE at national and regional level. NB: Luxemburg's values for the isolated case are not shown as they are 8760 hours (the whole year).**

Figure 54 shows, for each country and the whole region, LOLE and ENS values based on Antares simulations, considering the 'Central Case' and normal weather conditions (climate database 2001-2011). The 95 percentile values represent the value of LOLE and ENS close to the highest value over the simulations (95% of the values are lower than the 95 percentile and only 5% are greater).

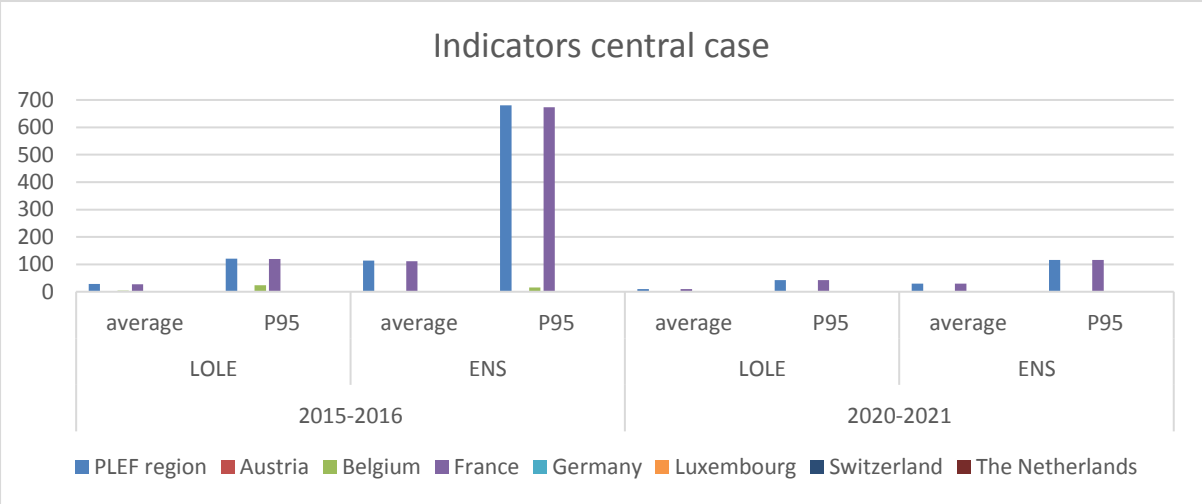


**Figure 54. [PLEF] LOLE and ENS results for the central case scenario (operational reserves do not contribute to adequacy).**

Another two figures are presented in the report for the whole region and each country individually. First, (see Figure 55) the graph of the cumulative probability distribution function of the minimum remaining thermal available capacity over 220 points (one for each Monte Carlo year simulated).

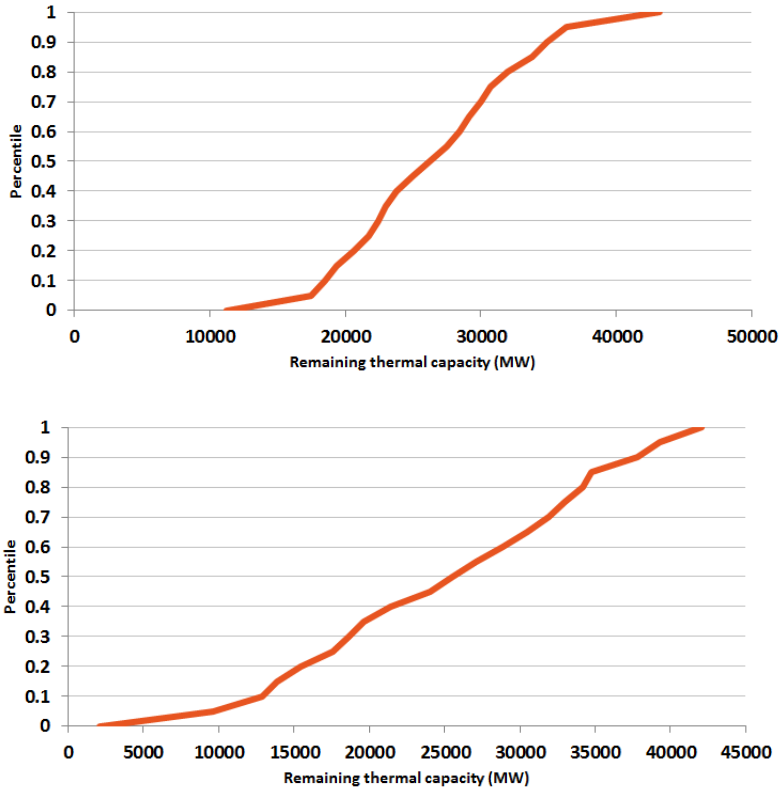


**Figure 55. [PLEF] Cumulative probability density function of the minimum Remaining Capacity. PLEF region 2015-2016 (up) and 2020-2021 (down). Base case (interconnected with strategic reserves without operational reserves). Normal weather conditions.**
**Source: Pentalateral Energy Forum, *Generation Adequacy Report* [28].**

Second, a graphical representation of the remaining capacity for the period of assessment. For each hour, minimum, maximum and average value of the RC are shown (Figure 56).

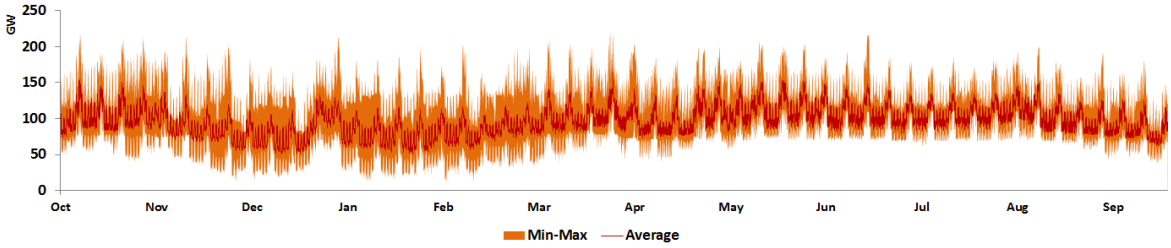


**Figure 56. [PLEF] Hourly remaining capacity. PLEF region. Short-term assessment (2015-2016).**

## Remarks

The Pentalateral Energy Forum group has applied a probabilistic method similar to the ENTSO-E target one. Something very interesting in the report (Chapter 5) is the analysis of the differences between the results obtained in the assessment with the results in the national reports. This shows how the different assumptions in the models produce different results in the adequacy studies.

# 3. Comparison between Member States methodologies

## 3.1 Introduction

The main objective of this chapter is to do a comparison between Member States medium- and long- term Generation Adequacy Assessments with the focus on the methodological procedure and with less focus on the regulatory aspects. Some countries and ENTSO-E perform a short-term adequacy assessment with a focus on the next 6 to 12 months but these short-term horizon studies are out of the scope of this report.

Approaches to generation adequacy assessments in individual countries apply different methodologies, and their relevance in the process of ensuring generation adequacy features significant differences. In addition, some countries do not publish the results of any generation adequacy assessments.

There is not currently a generally accepted definition of Generation Adequacy, the factors covered by the process of assessing it and the relationship between them. A variety of reliability standards for the adequacy assessment exists within European Countries. All of these elements are due to the fact that the generation adequacy has largely been considered, until now, a national issue. Since the adoption of the Third Internal Energy Market Package (1 COM(2014) 910 final of 16.12.2014), electricity policy decision has enabled competition and increasing cross-border flows of electricity. With the introduction of the so-called 'market coupling' and 'flow-based' capacity allocation, electricity can more efficiently be traded across Europe. Because of these ongoing changes, the process of ensuring generation adequacy needs to be coordinated to guarantee the security of supply in all the Member States.

Electricity generated from renewable sources has become one of the most important sources of electricity in Europe and has led to a growing concern for long-term capacity adequacy in the market; consequently the variable and uncertain nature of the RES needs to be properly assessed.

## 3.2 Comparison of methodologies

One of the first questions that immediately arise from this analysis is the time horizon of the assessment. Table 26 shows that there is not a uniform reply. The time frame of the analyses ranges from 5 years (Great Britain) to a 10 year perspective (Belgium, Ireland and Northern Ireland) and scenarios with a time frame of up to 15 years (the Netherlands) as is established in EU Directive 2005/89/EC.

| Country | TSO | Regulator | Last GAA published | Periodicity | Time Horizon |
|---|---|---|---|---|---|
| UK | National Grid<br>SONI (NI)<br>SHE transmission<br>SPT transmission | OFGEM | 2014 | Every year[1] | Next five winters 2014/15-2018/19 |
| France | RTE | CRE | 2015 | Every year | 2020 |
| Belgium | Elia | CREG | 2014 | Every 2 years | 10 years or more |
| Ireland | EirGrid | CER | 2014 | Every year | 2015-2024 |
| Northern Ireland | SONI | NIAER | 2014 | Every year | 2015-2024 |
| Spain | REE | CNE | 2015 | At least every 6 years | 2015-2020 |
| Portugal | REN | DGEG | 2013 | Every 2 years | 2013-2030 |
| Netherlands | TenneT | ACM | 2014 | On 2 years | 15 years |
| PLEF: Austria, Belgium, France, Germany, Luxembourg, Switzerland, Netherlands | TenneT (NL)<br>Elia (BE)<br>RTE (FR)<br>TenneT (DE)<br>Swissgrid (CH)<br>Creos (LUX)<br>APG (AT) | ACM (NL)<br>CREG (BE)<br>CRE (FR)<br>BFE (CH)<br>BUNDESNETZAGENTU (DE)<br>E-Control (AT)<br>ILR (LUX) | 2015 | Not available | Two winters: short-term 2015/2016 and mid-term 2020/2021 |

(1) The Department of Energy and Climate Change has remove this obligation from 2015 onwards, after the decision to introduce a capacity market from winter 2018/2019.

**Table 26. Member States sources, periodicity and time horizon of the generation adequacy assessment.**

It is worth mentioning that the Dutch report remarks that the results for this 15 years' time horizon has to be considered with caution as there is a high uncertainty in the evolution of demand and generation fleet. Indeed, the time horizon is a trade-off between the uncertainties in models and inputs (uncertainty increases over the time horizon) and the time required to plan and make future investments.

Another element to analyse is the granularity of the assessment. For example, Spain performs the analysis for years 2013, 2019, and 2020, while Portugal performs the analysis for all the years between 2013 and 2030. Great Britain's assessment only considers the winter period. As LOLE is assessed as hours/year, comparison of results among countries with the whole year versus only winter should be considered with caution although those countries which assess only winter periods are assuming implicitly that the summer demand is significantly lower than winter demand and the system will not suffer severe conditions in that period of the year. Finally, the assessment is done with hourly data except Great Britain, Ireland and Northern Ireland which use half-hour data.

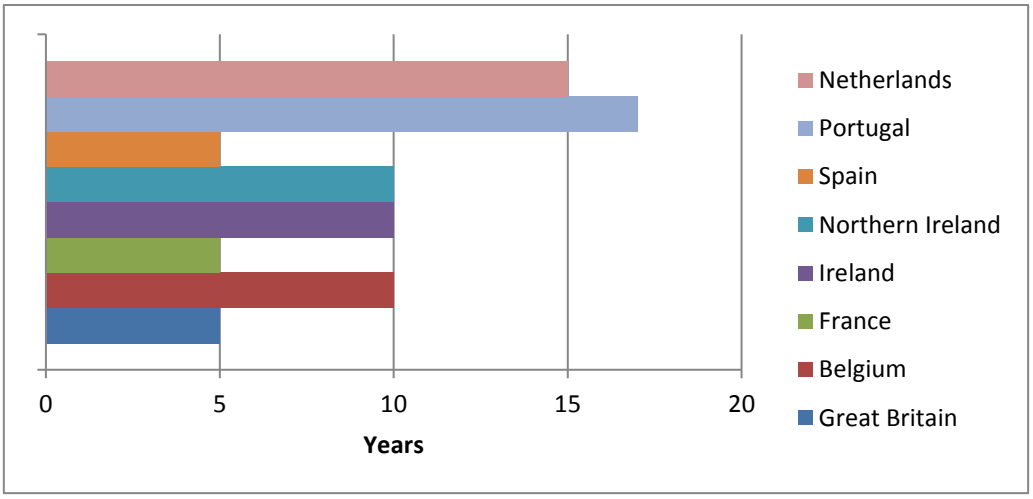


**Figure 57. Time horizon of National Adequacy assessments.**

Table 27 shows how the tendency in Europe is to move towards probabilistic assessments which can consider all the stochastic elements of the system (outages, RES generation) in a more realistic way.

| **Country** | **Type of the model** | **Tool** |
|---|---|---|
| **Great Britain** | Probabilistic: Non-sequential Monte Carlo | |
| **France** | Probabilistic: Sequential Monte Carlo | ANTARES |
| **Belgium** | Probabilistic | |
| **Ireland**<br>**North Ireland** | Probabilistic: Analytical | AdCal<br>Plexos® |
| **Spain** | Deterministic | |
| **Portugal** | Probabilistic: Sequential Monte Carlo | VALORAGUA: Market Model<br>RESERVAS |
| **Netherlands** | Probabilistic: Analytical approach | Analytical approach |
| **ENTSO-E** | Deterministic | |
| **Pentalateral** | Probabilistic Sequential Monte Carlo | ANTARES |

**Table 27. Modelling approach.**

Something that is worth mentioning is how the decision on methodology is taken by the TSO. Great Britain develops the model with a consultation process with industry, academics and consultants. Every year Ofgem has opened a consultation on methodology to get views on the validity of the approach. Also, Ofgem had an Academic Advisory Group to discuss the validity of the methodology and possible improvements. Something similar happens in the French case. In most of the cases, there is not information regarding this process.

## 3.3 Input data

Independently of the type of model (deterministic or probabilistic), demand and generation models shall be combined to perform the risk assessment (to check if there will be enough generation capacity to cover demand). So, the assumptions done to establish the future generation and demand will have an important impact on the results. To estimate demand and generation, two different kind of mathematical procedures need to be combined: an analysis of historical data to adjust *ex post* models to project future values, combined with long-term forecasting and prospective methods applied to generation and demand.

Regarding historical data, different characteristics should be explore: the length of the historical data, type of data, sources, correlations, etc.

### Generation

Regarding projections for generation, the main drivers are the decommissioning of the oldest thermal power plants due to the entry into force of the Industrial Emissions Directive 2010/75/EU, from 1 January 2016, and the mothballing of gas power plants due to unfavourable current market conditions for them. Other parameters to consider are the availability of conventional generators (see Table 28) and how hydro, wind and solar generation are modelled.

Hydro, solar and wind generation are very sensitive data. Hydro is very difficult to model, with several factors affecting the energy produced by a generator (optimisation portfolio of generation capacities in the same river, other uses of water, pumping optimisation, etc.). Long-term historical data are used to analyse hydro generation (for example, Portuguese data cover 30 years) which reflects the large variability of this resource. The main concern regarding wind is that for some countries there is not (or not enough) historical data (at least for offshore wind). Ireland and Northern Ireland are considering the capacity credit of the wind which is determined by subtracting a forecast of wind's half-hourly generated output from the electricity demand curve. The Irish TSO takes 2012 wind profiles as the reference as the capacity value for that year is very close to the average year (see Table 29).

| **Country** | **Availability of conventional generators** | **Source** |
|---|---|---|
| Great Britain | Yes. There is also sensitivity analysis regarding availability of gas power plants. | Based on the historical data (last seven winters). |
| France | Only explained for nuclear power plants. Two different availabilities, one for winter and one for summer. | Nuclear based on historical data. Rest based on ENTSOE reference values. |
| Ireland<br>North Ireland | Yes, consider high impact low probability events . | Based on historical data. |
| Spain | No info on how it is assessed. | |
| Portugal | No info on how it is assessed. | |
| Netherlands | Based on the information provided by producers. Sensitivity analysis considering historical average (which present lower values). | Based on the information provided by producers. |
| ENTSO-E | Yes. | Reported by TSOs. |
| Pentalateral | Yes. Based on type of thermal unit, fuel and age. | Based on ENTSOE reference values. |

**Table 28. Comparison regarding availability of conventional generators parameters.**

## Demand

Some countries have already detected a decoupling between GDP growth and energy demand. Also, energy efficiency plans, demand side management, electric vehicles and the electrification of other uses will change the energy consumption patterns in the near future. Table 30 presents a comparison among countries about the parameters considered to estimate future demand scenarios.

One key element of historical data is to see how many years they cover. The most common approach is to use at least 10 years for wind and 30 for hydro (if they are available). For weather data related with demand, some countries and ENTSO-E use the criteria 'once every 10 years' although others use 25-30 years of historical data.

| Country | Hydro | Wind | Correlation |
|---|---|---|---|
| Great Britain | | | |
| France | | ENTSO-E pan-European climate database (from 2001 to 2011). | Spatial correlation of wind and PV is considered. |
| Ireland<br>North Ireland | | Wind capacity factors are estimated with historical data assessing the ELCC. | |
| Spain | Average availability < 50%. Do not mention how it is assessed. | Wind availability at winter peak demand is 9%. Do not mentioned how it is assessed. | Not mentioned. |
| Portugal | 40 historical years are considered. Wet reference conditions are estimated with an average of 1966, 1978 and 1979, dry conditions with the average value of 1981, 1992 and 2005. | Wind is assessed splitting the territory in regions with different wind behaviours, using historical wind series. | Not mentioned. |
| ENTSO-E | | Pan-European climate database (14 years). | |
| Pentalateral | Hydro profiles are developed based on years 1999, 2011 and 2008 for wet, dry and normal profiles respectively. | ENTSO-E pan-European climate database. | Correlation between wind, demand and solar is considered. |

**Table 29. Consideration of wind and hydropower generation.**

| | GDP | Energy Efficiency | Electric Vehicles | Weather normalisation | Electrification of new uses | Estimation by sectors |
|---|---|---|---|---|---|---|
| Great Britain | x | x | x | x | x | x |
| France | x | x | x | x | x | x |
| Spain | x | x | | | | |
| Portugal | x | x | x | | | |
| Ireland | x | x | | x | x | |
| Netherlands | x | x | x | | x | x |
| ENTSO-E | Data reported by TSOs | | | | | |
| Pentalateral | x | x | x | x | | |

**Table 30. Elements to assess demand.**

## 3.4 Indicators used by Member States

The most common indicator employed by Member States is LOLE. Most of the countries complete the information provided by LOLE with other indicators, mainly EENS and excess or deficit of capacity (see Table 31).

| Country | Indicator | Target value |
|---|---|---|
| Great Britain | LOLE | 3 hours (Winter) |
| | Capacity margin | |
| | EENS | |
| | 1 to n probability of controlled disconnections | |
| | Equivalent Firm Capacity of Wind | |
| France | LOLE | 3 hours |
| | EENS | |
| Belgium | LOLE | 3 hours |
| | LOLE P95* | 20 hours |
| | ENS (energy not served)** | 3500 MW during LOLE hours |
| Ireland | LOLE | 8 hours |
| | EUE (expected energy not served) per million | 34.5 |
| Northern Ireland | LOLE | 4.9 hours |
| | EUE (expected energy not served) per million | 33.8 |
| All-island (Ireland + Northern Ireland) | LOLE | 8 hours |
| Spain | Coverage index assessed for the summer and winter peak demand. | 1.1 |
| Portugal | LOLE | 8 hours |
| | EENS | |
| | Probabilistic coverage index of the peak demand (ICP) | ICP ≥ 1.0 for a 95% confidence interval |
| | Many others | |
| Netherlands | LOLE | 4 hours |
| ENTSO-E | RC | RC >0 |
| | | RC> ARM |
| | RLPI | |
| | REPI | |
| | RCR | |
| Pentalateral | LOLE | There is no regional target |
| | EENS | |
| | Remaining capacity | |

* LOLE P95 is a percentile 0.95 (1 out of 20 probability) over the future states simulated.

** The amount of energy that not can be delivered by local generators or through import from neighbouring countries (limited to 3500 MW) during the LOLE hours.

**Table 31. Most common reliability indicators assessed by Member States.**

## 3.5 Scenarios

Adequacy assessment is based on the forecast of future generation mix and demand. Also, the models include some simplifications. To cover the uncertainty in these elements, the assessment is done considering different evolution of one or more parameters of the models to check how the results change. The number of scenarios is shown in Table 33.

## 3.6 Reserves

Reserves means the amount of generation capacity available to the TSO to balance constantly energy demand and supply and to maintain voltage and frequency within their margins. If this amount of capacity is considered to be available for adequacy purpose or not, has also an impact on the results.

| **Country** | **Reserves** | **Model** |
|---|---|---|
| Great Britain | Largest infeed loss. | It is considered as an additional demand. |
| France | | |
| Ireland | Not considered. | |
| Northern Ireland | Not considered. | |
| Spain | Not considered explicitly in the model. | Considered into the 1.1 target of the coverage Index. It is said that the TSO needs 2000 MW as reserves to operate securely the system. |
| Portugal | Operational reserves are considered as the sum of unexpected wind generation variations, unexpected changes in demand and changes in the available capacity due to unavailability. | Estimated for each hour with RESERVAS tool. |
| Netherlands | A reserve factor is estimated as a ratio between the maximum available capacity and the peak demand. | |
| ENTSO-E | Yes. | System service reserves are considered as Unavailable Capacity. |
| Pentalateral | Yes, two type of reserves are considered:<br>• Operational reserves: primary, secondary and tertiary reserves in all the PLEF countries.<br>• Strategic reserves: considered only for Belgium and Germany. | Different assumptions (considerations) depending on the sensitivity analysis carried out. |

**Table 32 Comparison of interconnection consideration**

| Country | Demand | Generation | Total | Other sensibilities |
|---|---|---|---|---|
| Great Britain | 4 different scenarios with different assumptions on generation and demand. | | | 16 sensitivities considering the variation of one parameter:<br>- Supply (4 sensitivities)<br>- Demand (4 sensitivities)<br>- Import/export (3 sensitivities)<br>- Availability of conventional generation (2 sensitivities)<br>- Low wind availability (1 sensitivity)<br>- Weather (temperature) 2 sensitivities |
| France | 4 scenarios | 2 scenarios | | Isolated system |
| Ireland | 3 scenarios | 1 scenario | 3 scenarios | All-island assessment |
| Northern Ireland | 3 scenarios | 1 scenario | 3 scenarios | |
| Spain | 3 scenarios | 1 scenario | 3 scenarios | Dry year |
| Portugal | 2 scenarios | 2 scenarios | 3 scenarios | |
| Netherlands | 2 scenarios | - Base scenario<br>- Sensitivity A: unavailability of conventional generators based on historical data<br>- Sensitivity B: Sensitivity A + less new installed capacity<br>- Sensitivity C: Sensitivity B + wind and solar capacity contribution 10 and 0 % | 4 scenarios | Isolated system |
| ENTSO-E | 1 scenario | 2 scenarios | 2 scenarios | |
| Pentalateral | 1 scenario | 1 scenario | 1 scenario | - Extreme weather conditions<br>- Isolated system<br>- Different assumptions on operational and strategic reserves<br>- DSR analysis for France |

**Table 33. Comparison of scenarios among national and regional assessments.**

## 3.7 Interconnectors

Most of the countries have shown the importance of interconnection capacity to provide energy in moments of peak demand. Also, something mentioned, for example in the PLEF assessment, is the importance of assessing the use of the interconnectors and the available capacity in neighbouring countries. If interconnectors have already been used at maximum capacity, available generation in other countries cannot provide support at peak demand moments as the interconnectors cannot transmit more energy. On the other hand, if interconnectors can deliver the energy but neighbouring countries don't have excess available capacity (for example, due to overlap in peak demand periods), adequacy cannot rely on imports.

Although it is clear the importance of consider interconnection capacity in adequacy assessments, how interconnectors are modelled is far from being harmonised as can be seen in Table 32.

| **Country** | **Interconnections considered?** | **Model** |
|---|---|---|
| Great Britain | Yes. | Based on the analysis of historical power flows. |
| France | Yes, first and second neighbouring countries are considered. | NTC. |
| Ireland and Northern Ireland | Yes. | Based on an estimation of import and export capacities. |
| Spain | No. | Not considered . |
| Portugal | No until 2014. After that, yes. | NTC = 10%. |
| Netherlands | No in the assessment of LOLE. In a second step, the estimated generation capacity surplus/deficit is compared with the available transmission capacity for export and import respectively . | |
| ENTSO-E | • No in the assessment of Remaining Capacities of national assessments. In a second step, the estimated generation capacity surplus/deficit is compared with the available transmission capacity for export and import respectively.<br>• The Pan-European Assessment considers interconnectors as the key element. | • Import and export capacities are reported by the TSOs.<br>• An optimisation to minimize power balance at European level is performed. |
| Pentalateral | Yes. | Winter and Summer BTC are considered. |

**Table 34. Comparison of interconnection consideration.**

## 3.8 Demand Side Response

Demand Side Response is consider a key element for near future management of the grid. During peak hour times this tool can provide the right signal to some customers to reduce their consumption. Although it is seen as an important element for the near future it is very difficult to include in the regional or pan-European models as each Member State has a variety an heterogeneous demand side topologies

| Country | DSR programmes implemented | Is DSR considered in the assessment? |
|---|---|---|
| Great Britain | Yes | Yes |
| France | Yes | Yes |
| Ireland | | |
| Northern Ireland | | |
| Spain | Yes | No |
| Portugal | | |
| Netherlands | | |
| ENTSO-E | | No |
| Pentalateral | Yes | Yes, in a simplified way |

Table 35. Comparison of interconnection consideration.

## 3.9 Flexibility assessment

Flexibility issues are gaining more and more attention due to the expected increase of their need due to the increase of non-dispatchable generation. Some countries have already started to include a flexibility assessment as part of the generation adequacy evaluation.

| Country | Is there flexibility assessment? | How? | Indicators |
|---|---|---|---|
| Great Britain | No | | |
| France | Yes | Analysis of residual load | Daily variability of residual demand<br>Weekly variability of residual demand |
| Ireland | No | | |
| Northern Ireland | | | |
| Spain | No | | |
| Portugal | Yes | As sub-hourly constrains | Curtailment<br>Maximum power at overproduction<br>Probability of overproduction |
| Netherlands | | | |
| ENTSO-E | Yes | Analysis of residual load and 1-hour residual load ramps | RES curtailment risk.<br>Maximum 1-hour ramping up and down values |
| Pentalateral | No | | |

Table 36. Comparison of flexibility assessments.

## 3.10 Conclusions

A comparison of the processes for ensuring generation adequacy at a national, regional and pan-European level reveals an extremely heterogeneous picture, but some trends may also be discerned.

- What is clear is that all the countries agree with the positive impact of the increase in the interconnection capacity between them. A very frequent sensitivity analysis is to assess the adequacy in the case of isolated country to highlight the contribution of the interconnection capacity in the adequacy of the system. What is still far from being accomplished is a harmonisation of how to model the interconnection capacity.
- Most of the countries/regions (France, Great Britain, and the Netherlands) have already changed the way they forecast demand. The direct relation between GDP and energy consumption is not valid any more as other parameters will have influence in the demand pattern, as for example, energy efficiency measurements, electric vehicles, penetration of heat pumps, etc. The new tendency is to forecast future consumption by sectors (residential, tertiary, industrial, transport, etc.), new uses of electricity and energy efficiency measures among others.
- Regarding renewable energy consideration in the assessments, the variety of approaches is very important. Also, the details about how the future generation patterns are forecasted is, in most of the cases, not very well detailed.
- Countries try to reduce the uncertainty in the results assessing the adequacy with a variety of scenarios. The main parameters for the sensibility analysis are (a) different demand growth patterns (although it could come due to different GDP assumptions, energy efficiency penetration, etc.), (b) different hydro conditions (wet, normal or dry), (c) severe weather conditions (mainly temperature which increases peak demand), (d) isolated versus interconnected systems and (e) different availabilities of dispatchable generators. Some countries, as for example the UK, provide a very complete set of sensitivity analyses to complement the four scenarios of the assessment.
- Regarding methodologies the tendency is to evolve to probabilistic models as ENTSO-E is already doing.
- Demand side response is a key element for the future although in most cases it is not considered or considered in a very simplified way. A very challenging aspect is to aggregate the response from the residential sector as different options are available in each country.
- Reserves are, in some cases, not considered or not very well explained. In the case of modelling only day-ahead markets, they are out of the scope of the assessment, although its relevance increases as renewables penetration does.

# 4. Conclusions and future perspectives

## 4.1 Conclusions

Generation adequacy is important for energy consumers because it seeks to ensure that their electricity supply will remain secure and available when it will be needed. A coherent methodology to assess adequacy is important to facilitate the planning process of new facilities to deliver energy supply and, at the same time, avoid over-investment which has, as a consequence, an increase in the cost of energy and hence a loss of competitiveness for the EU economy.

As was mentioned in the previous chapter, although there is wide variety of approaches to assess generation adequacy among Member States, some tendencies can be highlighted:

- ENTSO-E has proposed an evolution of its adequacy assessment moving from a deterministic power balance to a sequential Monte Carlo probabilistic approach with the aim of assessing the adequacy of the system not only at moments of peak demand but also estimating the requirements (as for example flexibility) future generators should have. Some countries have already implemented a methodology similar to the target one as for example Portugal, France or the Pentalateral Energy Forum region.
- Some countries have considered flexibility needs in their assessments: not only the amount of capacity is important, but also their attributes. Generation capacity is assessed against load but also residual load is compared with the dispatchable generation to estimate the capability of the existing fleet to balance residual load. Estimation of flexibility needs is relevant for TSOs.
- It seems essential to perform national and also regional studies to assess the impact of RES generation on the security of supply as well as the extent to which market areas within a region can support each other, modelling the role of interconnectors and to assess regional perimeters to check the simultaneity of stress situations among neighbouring countries.
- Regarding interconnectors, not only their capacity, but also the available capacity of generation at both sides need to be considered. This is mainly done through the estimation of the peak demand period coincidence and the way interconnectors are being used (for example, PLEF report shows that including DSR in Germany would not have an impact on the adequacy in France if previously the interconnection between the two countries was been used at its maximum capacity).
- What is far from harmonised is how the interconnectors are modelled.
- TSOs have become aware that demand forecast based only on GDP evolution is no longer valid. Many other factors should be considered, for example energy efficiency programs, environmental legislation, electrification of some applications (mainly heat pumps for heating), new uses (electric cars) and so on.
- The evolution of the gas fleet is the most uncertain input data of the generation forecast. The number of mothballed power plants will depend on the evolution of demand, the oil and gas prices, the evolution of $CO_2$ emission prices and the future market design.
- Also, the increased amount of renewable energy in the market is producing two effects on gas power plants: On one hand, gas power plants are displaced from the market, with a decrease of their utilisation. On the other hand, as renewables require more balancing services, gas power plants are subject to frequent cycling and ramping up and down requirements. Both elements are challenging the estimation of their future availabilities.
- Renewable energies (wind and solar PV) are no longer considered to be unavailable capacities although their contribution to resource adequacy ranges from about 5% to 40% of their installed capacity, depending on their correlation with demand and periods of time used to estimate this value. What is far from harmonised is how to estimate their contribution in the assessment.
- Different assumptions in models and different input data provide different results. For example, *Pentalateral Energy Forum Generation adequacy report*, Chapter 5 (see [28]) provides a comparison between the results in that report and the national assessments, which can be seen as an evidence

of the need for a minimum harmonisation among countries and the regional and pan–European assessments, not only in the methodology but also in the input data collection.

- DSR is seen as a key element to consider as it will play a more essential role in the near future.
- Synchronous data are essential for temperature-sensitive load models, harmonised probabilistic hydrological data, and also to properly take into account spatio and temporal correlation among generation sources and demand.
- Reserves are an important element of the system as they cope with the unexpected events in the system. Its role is important also in the assessment of flexibility needs, although in some cases they are not considered.
- 15 years' time horizon is considered, in most cases, as too long term to estimate future generation and demand scenarios as the uncertainty is high.
- What is seen as heterogeneous is how many Monte Carlo simulations are needed in the probabilistic assessments. They range from 1 000 in the France case, to 200 in the Irish case. The converge criteria is not detailed in the reports.

## 4.2 Future perspectives

The objective of an adequacy assessment is to explore if demand can be supplied in average (or normal) conditions but also in extreme conditions (or combinations of extreme conditions). The probability of these extreme events and the possible simultaneous occurrence among neighbouring countries is of utmost importance. Then, the need for synchronous data for all the countries to check the temporal and spatial correlation of extreme events is real.

One of the first open questions that emerges from this study is how many years of historical data are required to cover the whole set of events and what is the probability that such historical events will occur again in the future. Climate change will impact temperatures (and so demand), cycles of water (then generation from hydro and efficiency of thermal power plants), but also new uses of electricity, energy efficiency measurements and so on will imply that the same pattern will be not repeated exactly the same. Nevertheless, enough climate years to cover representative samples of the climatic variations are needed.

Key elements to include in future adequacy assessments are the role of interconnectors, reserve requirements, demand side response (DSR) and capacity remuneration mechanisms (CRM). Regarding interconnectors, the future trend would be to develop flow-based market coupling models, to reflect in a realistic way the future flows at the European level. Reserves are essential to balance the system, so they should be properly modelled and accounted for (this implies that more than day-ahead markets shall be modelled). In a similar way, DSR will play a key role by providing flexibility. The wide portfolio of DSR programs in the different Member States makes modelling them very challenging. In addition some countries are putting in place Capacity Remuneration Mechanisms. They will have a decisive impact in the adequacy assessment, not only in the particular country but also at the European level, as larger power flows are foreseeable to better integrate the increasing amount of renewables.

Future availability of dispatchable generation is unknown as it depends on future ramping and cycling requirements together with the evolution of their role in the market.

All of the above-mentioned elements pose a number of challenges to traditional generation adequacy assessments. A well-recognised instance is flexibility (capacity of the system to cover fast and deep changes in the net demand), whose importance is growing along with the penetration of non-dispatchable energy generation. For supporting adequacy assessments, models will have to offer a long time horizon, increasing resolution (short time steps) for evaluating the balancing requirements, and a very detailed characterisation of the generation units and their functioning in the market, which derives in an extremely complex task. Indeed, the system is evolving to a very complex one. Keeping things as simple as possible will avoid constant revisions of the fundamentals and the basic assumptions of the assessment methodologies used by a vast number of stakeholders.

It is clear that there is a need for national adequacy assessments complemented by regional and pan-European studies. What is needed, along with a minimum harmonisation of models and inputs, is to determine the scope of each assessment as increasing the size of the model cannot be performed at the same time as increasing the time step, details and granularity.

The results coming from the probabilistic models are the expected values of the different indicators. Another interesting piece of information is the variation around the expected value to see the uncertainty around this estimation.

Distributed generation is specifically addressed in some particular cases. For example, the British assessment considers distributed wind and includes its generation in the estimation of the generation from this source of energy. The Dutch assessment considers little CHP from the agricultural sector. TSOs perceive this generation as a reduction of demand but it has a deep impact in the residual load. For example (see French report [17]), PV generation significantly changes the residual load profile at midday hours.

Modelling of hydro power plants is very challenging but is and will be very relevant for balancing renewable generation specially in moments of over-generation where pumping hydro avoids curtailment of the renewable generation. An example can be seen in the Portuguese report [15].

Table 37 is a summary of the main elements that impact the Generation Adequacy Assessment.

**Table 37. Current Discussion on 'new electricity market design'.**

| Elements | Impact on GAA | Obstacles | Enablers | Level of GAA assessment |
|---|---|---|---|---|
| Scarcity pricing ([5]), electricity market price that adequately reflect scarcity in the market and signals the business investment opportunities in the system | Represent a market signal to ensure adequate capacity on average (1) over long periods (temporal scarcity); (2) for all players in the market ([6]) (power generators, storage, DS, ect.); and (3) across regions (location scarcity). | Price caps; capacity mechanisms (efficient scarcity prices lessen the need for capacity mechanisms, nevertheless it may still be desirable to have a (temporary?) capacity mechanisms if regulators wish to maintain a minimum level of reliability and as a safety net to ensure reliability, particularly during decarbonisation efforts). | Price hedging (instead of price caps) to insure from the risk of price volatility and cash-flow uncertainty. Transparent information, long-term contracts ([7])([8]) between generators and consumers to hedge against electricity price risk stemming from uncertain carbon pricing policies and renewable policies to provide stable revenue streams to generation owners, incentivising investment in new capacity. | Medium-/long-term analysis reflecting the time of the investments, the location and the technology. |
| | | Poor interconnection and poor cross-border capacity. | (Day-ahead) market coupling, cross-border participation to capacity adequacy . | Regional/EU. |

([5]) National grid, the UK's principal Electricity and Gas Transmission System Operator, implements a Balancing Use of System Charge (BSUoS), which is an *ex post* charge paid by generation and demand customers which reflects the scarcity of electricity, the costs of balancing the system and network scarcity on a half-hourly basis, however on a non-locational basis. BSUoS reflects the short-term costs of the network, including transmission scarcity. The cost reflectiveness of BSUoS has recently been sharpened through the Electricity Balancing Significant Code Review. The Transmission Use of System Charge (TNUoS) is an *ex ante* tariff levied on generation and demand customers on an annual basis. This charge signals the marginal long-run cost of establishing and maintaining network capacity and so the relative locations of generation and demand are reflected in the charge. The longer term nature of TNUoS allows customers to make informed investment decisions about where to site future plants.

([6]) In competitive energy-only markets, where the source of revenue to generators comes from the sale of electricity, the ability to earn high scarcity rents at peak times is essential to incentivising investment in capacity. Having prices reflecting the actual situation of the electrical system is also essential to incentivise consumers' participation in markets.

([7]) A potential barrier associated with long term contracts is that they may suppress the price signals required to encourage:

• market innovation (such as demand side response); • development and deployment of new technologies such as storage; • investment in new interconnector capacity; and • supplier hedging contracts.

([8]) Contracts for Difference as used in the UK.

| Elements | Impact on GAA | Obstacles | Enablers | Level of GAA assessment |
|---|---|---|---|---|
| Capacity mechanisms | Generation adequacy level is inversely proportionate to the 'amount' of capacity mechanisms introduced in the country. GA will vary based on the country implementation of specific measures like scarcity pricing, price-based demand response, reliability standards, etc. | Energy markets operate along non-uniform lines with respect to the adoption of capacity mechanisms ([9]). | | Country. |
| Short-term/real-time markets with higher temporal and geographical resolution | Will increase the information *about real time locational marginal generation prices* needed for security-constrained dispatch, for managing deviations, and solving congestions and reduce/hedge the uncertainty around RES and (residual) load. All this will increase the ability of the system to cost-effective (optimal) level of capacity. | High resolution of (real-time) locational marginal generation prices, which are known by European system operators, are not published. Poor liquidity in intra-day and balancing markets due to high levels of uncertainty. | Intra-day ([10]) and balancing markets ([11]) coupling; enable contracted positions to be closer to real time where forecasting accuracy is significantly improved; transparent information on (real time) locational marginal generation prices. | As wide as possible, eventually across national borders and preferably at the regional level ([12]). |

([9]) The design of capacity mechanisms across MS is quite diverse. e.g. DE capacity reserve, climate reserve, network reserve — in EU: strategic reserve, capacity payments, capacity auctions, capacity obligations, reliability options, price-based or volume-based, centralised or decentralised, market-wide or targeted at specific plants or technologies.

([10]) XBID (Cross Border Intraday) Project is a project that will deliver Intraday Trading in North Western Europe.

([11]) National grid already exchanges cross-border balancing services mainly with France through the IFA interconnector.

([12]) The definition of 'regional level' has to reflect the degree of interconnection.

| Elements | Impact on GAA | Obstacles | Enablers | Level of GAA assessment |
|---|---|---|---|---|
| Integration of RES | Knowing the amount of RES generation that can be integrated in the system drives the optimal level of all (other) generation (thermal plants) and flexible (storage, DSM, ect.) technologies. Assessment of flexibility requirements and measurements, effective wind and solar forecasting tools to be integrated in the GAA methodology. | Current low wholesale electricity prices undermine the business case for renewable generation (therefore current support schemes are still needed); current RES supporting schemes risk to suboptimal bidding behaviour of RES generation ([13]). Lack of appropriate price signals on the EU Emission Trading Scheme, which does not act today as an incentive for low-carbon technologies. | Stable carbon policy ([14]), incentivise flexible technologies for RES integration (electricity storage(?), interconnections, hybrid systems, ect.) and reduce unwanted curtailment; (temporary/short to medium term?) governmental supporting schemes harmonised across EU to avoid leakages effects towards more generous subsidies; (temporary/short to medium term?) ad hoc schemes to share long-term price risks between investors and consumers and keep the cost of capital low. (In the future?) renewable generation fully integrated to the market; (in the future?) phase out of priority of dispatch and RES submitted to balancing obligations (including participation to balancing markets where RES generators can offer system services — response, reserve, reactive power — that would increase the competitiveness of RES vs conventional more flexible generation). | Country level (for country specific balancing responsibilities, e.g. island nations such as GB); Regional level (different approaches to balancing in different geographical regions); EU level (for harmonised market rules and products/services to be trades across EU. |

([13]) Subsidised low-carbon investments, such as those subsidised through a FiT, are incentivised to bid the opportunity cost of the subsidy and thus bid inefficient, sometimes negative prices.

([14]) Carbon policy may also substitute public supporting mechanisms to renewables that risk to distort the market, but this is a long process so it will not be feasible for the time being.

| Elements | Impact on GAA | Obstacles | Enablers | Level of GAA assessment |
|---|---|---|---|---|
| Cross-border participation | Allows regional optimisation of supply sources and contributes to cost-effective generation capacity adequacy. Cross-border capacity needs to be included in the GA assessment. | Non harmonised market rules, non-coordinated system operators. | Stronger coordination and cooperation across national borders is essential to ensuring optimal cross-regional generation adequacy and network development plans. Merge system operators and allow them to operate assets of different transmission owners ([15]). Harmonised capacity products to enable cross-border trade. | Regional level. |
| Price volatility. Prices should be left fluctuating according to market conditions | More volatile but efficient prices would signal the need for investment in flexible generation, storage and demand response. These technologies participate to the optimal level of GA. | | Commercial hedging products give the opportunity to market participants to guarantee income against the uncertainty given by price volatility. | EU level. |
| Cooperation among MS, TSOs, ENTSOE, national and international authorities | The fields of cooperation touch upon the following five activities common grid model, capacity calculation, security analysis, outage planning, and generation adequacy. | Poor cooperation channels established between TSOs, national and international authorities, other organisation in the energy sector. | RSCIs (Regional Security Coordination Initiatives), (1) enhance the role of ACER from coordination to integration of energy systems across EU; (2) empower the representation of DOSs at all level of cooperation and (3) trade union organisations. | EU level for the methodology to measure adequacy (e.g. standard method for LOLE measurement);<br>Country level for setting the thresholds according to generating capacity margin or the national demand profile. |
| | System security; indicators and thresholds that are included in the GAA methodology. | | | |

([15]) In North America for instance, MISO operates part of the Canadian Network.

| Elements | Impact on GAA | Obstacles | Enablers | Level of GAA assessment |
|---|---|---|---|---|
| Participation of new players in the market (DS, prosumers, flexible generation, storage) | Availability of DR capacity diversifies the portfolio of flexible technologies. | Lack of market rules that enable DR to actively take part to the market. | Large scale deployment of DR (involve small and residential consumers together with the large industrial consumers that already offer DR services); retailers and balance responsible parties (or aggregators) — offering innovative tariffs to end consumers such as real time pricing, dynamic pricing, critical peak pricing, ect. — can aggregate the demand response potential and participate in wholesale, intraday and balancing markets on the demand side, buying their baseline consumption in advance and reselling the energy not consumed by their responsive consumer; harmonised and standardised products/services that enable greater opportunities from DSR across MS/markets to allow cross-country exchange. | Regional/EU level. |

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## Abbreviations and acronyms

| | |
|---|---|
| AAGR | Annual Average Growth Rate |
| ACS | Average Cold Spell |
| ARM | Adequacy Reference Margin |
| CAES | Compressed Air Energy Storage |
| CCGT | Combined Cycle Gas Turbine |
| CHP | Combined Heat and Power |
| CRM | Capacity Remuneration Mechanism |
| CI | Coverage Index |
| COPT | Capacity Outage Probability Table |
| DSM | Demand Side Management |
| EENS | Expected Energy Not Supplied. |
| ELCC | Effective Load Carrying Capability |
| ENTSO-E | European Network of Transmission System Operators of Electricity |
| FOP | Forced Outage Probability |
| FOR | Forced Outage Rate |
| GA | Generation Adequacy |
| GAA | Generation Adequacy Assessment |
| GDP | Gross Domestic Product |
| HILP | High Impact Low Probability |
| IEA | International Energy Agency |
| IED | Industrial Emissions Directive |
| IMF | International Monetary Fund |
| LOEP | Loss of Energy Probability |
| LOLE | Loss of Load Expectation |
| LOLP | Loss of Load Probability |
| NEEAP | National Energy Efficiency Plan |
| NREP | National Renewable Energy Plan |
| NTC | Net Transfer Capacity |
| REE | Red Eléctrica de España |
| REPI | RES Energy Penetration Index |
| RES | Renewable Energy Sources |
| RLPI | RES Load Penetration Index |
| RM | Reserve Margin |
| ROR | Run of River |
| SEM | Single Electricity Market |
| SO&AF | Scenario Outlook and Adequacy Forecast |

| | |
|---|---|
| TER | Total Energy Requirement |
| TSO | Transmission System Operator |
| VOLL | Value of Lost of Load |
| WEO | World Energy Outlook |

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