Investment criteria for generation capacity and interconnections in a regional electricity market

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Abstract

This paper deals with practical problems related to long-term security of supply in regional electricity markets, especially markets with structural congestions.
While the European Commission has explicitly recognized the general problem of security of supply and reliability in deregulated electricity systems in its EU-Directives 2003/54 and 2005/89. The main provisions contained in these Directives refer in fact to regulatory measures that should be taken at the national level.
In this context, the institutional rules regarding security of supply have evolved in different ways among the European countries: some countries have chosen to explicitly refer to an investment criteria, and have put in place the regulatory market mechanism needed to ensure that this criteria will be met; other countries have decided to keep a legally non binding investment criteria only, and lasly some European countries have decided to let the market prices decide on the level of investment in generation capacity without any criteria.
Yet the levels of security of supply are obviously interdependent in interconnected systems and we may expect to benefit from the relatively high level of interconnection in Europe to mutualize the cost of security of supply.
It nevertheless require methodological advances to improve the way interconnections are taken into account in the security of supply assessments.

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Introduction

Liberalization of the electricity market is presented by the European Commission (EC) as a means for reducing electricity prices, securing supply, improving efficiency and developing renewable energy production. As the number of electric entities increase and as their contributions with the market to security of supply are not clear, the second point seems not so obvious.

From the very outset of liberalization, the debate concerning the security of supply in the European power system has risen and has been reinforced in 2003 after the blackouts in North America and in Italy. This debate led the EC to explicitly recognize the general problem of security of supply and reliability in deregulated electricity systems in its EU-Directives 2003/54 and 2005/89.

The main provisions contained in these Directives refer in fact to regulatory measures that should be taken at the national level, whether concerning the definition of market participants' roles and responsibilities, or the market rules that could be adopted to maintain an appropriate balance between consumption and generation.

Furthermore, the EU-Directives do not give explicit information concerning the monitoring of the security of supply : at the European level, UCTE is in charge of the system adequacy forecast (SAF) report, at the national level, TSOs can use a variety of methodologies to monitor the security of supply.

In this context, the institutional rules and the technical aspects regarding security of supply have evolved in different ways among the European countries: some countries have chosen to explicitly refer to an investment criteria, decided on a national basis by public authorities, and have put in place the regulatory market mechanism needed to ensure that this criteria will be met; others have only decided to keep an investment criteria, without specifying any market rule to ensure its practical enforcement in a deregulated environment; and finally some do not refer anymore to any criteria.

Yet the levels of security of supply are obviously interdependent in interconnected systems and we may expect to benefit from the relatively high level of interconnection in Europe to mutualize the costs of security of supply. This question is all the more important as the European Commission asked to establish a European Energy Supply Observatory to monitor demand and supply at a EU level.

In this paper, we present and discuss the criteria chosen in western European countries to guide investments in generating capacity. In particular, we identify whether these countries explicitly refer to an investment criteria regarding generation, and if so which criteria (level, type…). We point to the hypotheses made regarding the use of cross-border capacity in peak period and assess their compatibility. Finally, we propose some methodological advances to improve the way interconnections are taken into account in the security of supply assessments and compare these proposals with the methods used by UCTE in its study "UCTE System Adequacy Forecast".

1. The management of security of supply in a liberalised electricity market

While security of electric power supply seems relatively natural in developed countries, the adaptation of the control and command rules that entailed a certain level of security of supply in the monopolistic context to a competitive one is not trivial.

1.1. Security of electricity supply before the liberalisation of electricity markets

Before the liberalisation of electricity markets, the security of electricity supply was generally enforced by a single electric utility, vertically integrated, and controlled by public authorities. The mission of this company was to build and maintain an electric system able to meet the consumers' demand, and to operate it safely. Investments in production capacity were determined by comparing the investment cost of the proposed capacity expansion plan to the savings that this new capacity would allow to make in the total production cost. Since consumers' demand and generation units' availability cannot be exactly known in advance, there is always some probability that their aggregate peak demand will exceed the production that is simultaneously available in the system. In consequence, the electric utility and public authorities had to agree on a reasonable limit, above which it would be too costly to guarantee consumers' security of supply.

This reasonable limit, that we will refer to as "investment criteria" for the rest of the paper, could take various forms. In the case of France, the investment criteria was explicitly defined as a unique value of lost load for consumers. The electricity utility would then design its capacity expansion plan such that on average (i.e. given a set of demand and production availability scenarios) the last megawatt hour produced by the electric system would cost as much as the value of lost load. In practice, the value of lost load criteria was translated into a number of hours of power interruption (loss of load expectation)[2]. In England and Wales, the former Central Electricity Generation Board's investment criteria was to reach a capacity planning margin of 24% (NGET, 2006). Though investment criteria can take various forms, it is still possible to find some equivalences: for instance, given the shape of the demand curve, and the capacities in each generation technology, it is possible to calculate a capacity margin percentage in terms of a unique loss of load expectation.

1.2. What became of the former investment criteria after the liberalisation of electricity markets?

The general reform that has affected the network industries since the beginning of the 80's, trying to transform vertically integrated monopolies in telecom, railways, airlines… also affected the electric power sector and led to the liberalisation of electricity markets, adopted through the European Directives 1996/92/EC and 2003/54/EC.

The liberalisation has separated the different missions of security of supply, and allocated them to different entities. Investment planning in production capacity is taken care of by electricity producers. This activity is no longer regulated by public authorities. Investment planning in transmission capacity is taken care of by the transmission owner, whereas the system operator is in charge of operating the electric system. In most systems, the transmission owner and the system operator are the same regulated entity (Great Britain being one exception in Europe).

Thus today, investment decisions in production capacity are made by several operators, independently. An operator will decide to invest if the investment is expected to improve the profits of the operator's portfolio. In other words, there is no coordination between companies to collectively reach the optimal capacity expansion plan as defined by the former public utility's methodology. Yet, according to the theoretical economics of electricity markets, the investments decided by the competing electricity producers should be equivalent to the investments of a public monopoly which tries to maximize the

[2] In its prospective system reliability report, the French system operator RTE refers to a planning criteria of max. 3 hours of power cuts per year, which has not been changed since liberalisation. Considering that a peaking plant's fixed costs are today about 43 000€/MW, the plant would need to face market prices above 14 000€/MWh in order to recover its total costs. Thus the implicit value of lost load of the "3h/year" criteria is today about 14 000€/MWh (RTE, 2007).

entire society's welfare. However, in both situations, the true maximization of the society's welfare can only be reached if consumers' true willingness to pay for electricity in periods of scarcity is known.

The new market paradigm supposes that the market receives a signal of consumers' willingness to pay their electricity. This signal replaces the implicit average value of lost load used in the old paradigm. Yet, for this signal to reach the market, it has to be made explicit by consumers to suppliers, and by suppliers to producers via the market. It would require profound changes in metering technology, as well as new ways of electricity contracting between suppliers and consumers. Until then, the market cannot know consumers' willingness to pay their electricity. Consequently the market today cannot infer what investments in production capacity must be made in order to satisfy consumers' demand.

While waiting for metering solutions that would allow the new market to reach the economic efficiency, there may be an implicit tendency among operators to follow the historic investment criteria. In some electric systems, there is an effort to maintain the old investment planning criteria as a value of reference, as long as the market cannot find its own. In those systems, the system operator typically publishes reliability reports, in which it evaluates what investments in production capacity the system needs in order to meet the old planning criteria. This criteria may be purely informative, if no implementation mechanism is put in place; it is the case for instance in England and Wales where the reliability reports intend mainly to guide the decentralised investment decisions. The criteria may also be binding if implementation mechanisms are put in place, which is the case in France where the transmission operator can organize public tenders if it fears that the criteria will not be met (Finon, 2007). In other systems, the system operator publishes reliability reports, but it has modified its methodology, or modified the value of reference (generally without explaining clearly why it has done so).

The next paragraph analyses in more details the generation adequacy reports that are made in western European countries.

2. A comparative analysis of TSO's methods for evaluating the level of security of supply in electric systems

In this section, we propose an in-depth analysis of TSOs' methods for anticipating and reporting on long-term security of supply in West-Europe. For this study, we have analysed the following zones or countries: France, Great Britain, Spain, Belgium, the Netherlands, Germany, Austria, Switzerland, Italy, and the Nordel zone (which covers Sweden, Norway, Finland and Denmark)[3].

Our first result is that in all the countries we reviewed, TSOs produce regular long-term security of supply reports. These reports evaluate the capacity of the electric system to cope with future electric demand, given plausible scenarios of investment in new capacity as well as decommissioning. Another common feature is the fact that TSOs continue to rely on physical indicators (either the reserve margin at peak load, the yearly energy reserve margin, or the expected power cuts duration) to estimate whether the electric system is able to deal with future demand. At this point, it is clear that the main criteria used by TSOs to base their analysis is a physical one, and not the explicit value of lost load for consumers.

2.1 the methods to evaluate the level of security of supply, and in particular the reference to an investment criteria, vary a lot among reviewed countries

The review of TSOs security of supply evaluation techniques reveals first quite a diversity of approaches. We present below the different approaches used to evaluate security of supply, and identify whether TSOs use any investment criteria in their appreciation of the level of security of supply. Whether possible, we try to establish the link between today's criteria and the criteria that was used by the former monopoly before liberalisation.

First, we observe that the planning horizon on which TSOs elaborate their security of supply report can differ quite sensibly. Nordel for example does not exceed a 3-year horizon, though it is considering extending it to 6 years (Nordel (2006a)). On the other side, Switzerland's security of supply report looks as far as 50 years ahead (AES (2006)). One can wonder why Nordel uses such a short time span, which does not bring any information to potential investors about the level of security

[3] The reports on which we base our study are either published by the TSO or an association of TSOs (France, Great Britain, the Netherlands, Germany, Austria, Switzerland, Nordel), or based on TSO data but published by the regulatory authority (Spain, Belgium). For simplicity, we will refer to the TSO as the publisher in the rest of the paper.

of supply the system would face when their investment comes online. The use of a very long time span, like Switzerland, is also questionable, as one cannot have the same accuracy in long term assumptions compared to medium term ones. The other systems use the same range of planning horizon, from 6 to 13 years. This horizon seems reasonable, allowing to consider the years when potential investments could improve the level of security of supply, while keeping sufficient accuracy in future demand and offer estimates.

France	13 yrs	Germany	10 yrs
Great Britain	7 yrs	Austria	10 yrs
Spain	6 yrs	Switzerland	30-50 yrs
Belgium	9 yrs	Italy	10 yrs
the Netherlands	8 yrs	Nordel	3 yrs, possible extension to 6 yrs

Table 1 - Planning horizon used in security of supply reports, by countries.

2.1.1. the three approaches to measure the level of security of supply

There are three main approaches used by TSOs to evaluate the level of security of supply: (1) a capacity margin analysis, (2) an energy balance analysis, and (3) a loss of load expectation (LOLE) analysis.

The first approach, most commonly used, is a capacity margin analysis, which evaluates the system's ability to serve the peak demand. This approach is used in the following countries: Great Britain, Spain, the Netherlands, Germany, Austria, Switzerland, Italy, and the Nordel zone. The peak demand is typically defined as one or two points in the year (winter peak, or summer and winter peaks), and is estimated according to plausible scenarios of the evolution of electricity demand. The peak system capacity can be defined in several ways, which may be source of confusion when comparing security of supply data. For instance, Germany (Verband der Netzbetreiber (2004)), Austria (E-Control (2005)) and Switzerland (AES (2006)) use an available capacity at peak according to the UCTE's definition ; it is calculated as the installed capacity, minus the unavailable capacity (mothballed units, maintenance, and outages), minus the largest production unit's capacity, minus the reserve capacity of the primary, secondary and tertiary reserves. Nordel uses a similar definition, though not referring to the UCTE. Great Britain (NGET(2006)) and Italy (Terna (2006), (2007)) simply use the installed capacity. Spain uses the installed capacity, minus potential outages and planned maintenance (Ministerio De Industria, Turismo Y Comercio (2006), Comisión Nacional de Energía (2006)). It also considers dry year conditions to estimate the available capacity of hydraulic resources. The Netherlands use an available capacity indicator, though it uses a 100% availability factor for thermal units.

As one can see, there is quite a variety of methods for calculating system capacity at peak load. This makes the comparison of security of supply level among countries quite problematic:

- TSOs do not have the same level of detail in their definition of system capacity. For example, some explicitly mention reserves for system services, while others do not even mention it. Besides, it is not clear for the reader whether the terminology employed has the same meaning among the different reports.
- TSOs also differ in their treatment of potential imports for serving peak load; this issue is analysed separately in paragraph 2.2.
- TSOs have their own recipe for considering exceptional events. For instance, Spain handles the hydraulic resources uncertainty by considering dry year conditions, rather than average ones, for hydraulic capacity. For its peak demand, Nordel considers winter conditions occurring once every 10 years for its 1 year-ahead balance, and normal conditions for its 3 years-ahead balance (Nordel (2006). Weather conditions can indeed be much more critical in some systems than in others, typically when hydraulic resources are significant (e.g. Nordel, Spain, Switzerland, Austria, Italy, France) or when peak demand is extremely sensible to weather conditions (e.g. the widespread use of electricity-based heating systems in France). In other words, the scenarios considered in estimating peak demand and available capacity at peak do not have the same probability of occurrence from one report to another, some using average conditions, others using special or extreme conditions. This also makes the comparison exercise more difficult.

The second approach is an energy balance analysis, which evaluates the system's ability to serve the yearly demand in energy. This approach is used in the following countries: France, Spain, the Netherlands, Switzerland, Italy, and the Nordel zone. It is more meaningful to use an energy balance analysis in systems where stock-based production (essentially hydraulic production) is important. Besides, an energy balance analysis also allows to take into consideration maintenance constraints, such as fuel charging of nuclear units, which are planned in off-peak seasons. Surprisingly, the

Netherlands also use the energy balance approach, though the Dutch system does not present any energy constraint characteristics. This energy balance approach also raises the same issues as the capacity margin approach when trying to compare the level of security of supply in the studied countries.

The third approach is a loss of load expectation analysis. It measures the security of supply in terms of expected duration of power cuts. TSOs generally calculates the power cuts duration resulting from numerous offer and demand scenarios. The obtained power cuts duration for each scenario allow to calculate an expected value of loss of load duration (LOLE, in hours/year). This approach is only used by France, Belgium, and the Netherlands, probably because of its complexity. This methodology is relevant when using a large number of scenarios. For example, France uses about 500 scenarios, based on combinations of temperature, capacity units availability, hydraulic flows and wind speeds scenarios. The Netherlands do not detail in their report how they apply the methodology, or how many scenarios are used in their model. According to their reliability report, Belgium does not seem to use a lot of scenarios (Commission de Régulation de l'Electricité et du Gaz (2005)). It is possible that the Dutch and Belgian TSOs use a significant number of scenarios in their LOLE computation, as can be expected for that type of exercise, but no such information can be found in their reliability reports.

	Capacity margin analysis	Energy balance analysis	Loss of load probability analysis
France		×	×
Great Britain	×		
Spain	×	×	
Belgium			×
the Netherlands	×	×	×
Germany	×		
Austria	×		
Switzerland	×	×	
Italy	×	×	
Nordel	×	×	

Table 2 – Methods used in national security of supply reports, by countries.

2.1.2 investment criteria in security of supply reports

Another major difference in TSOs’ approaches to evaluate system security of supply is the explicit use of an investment criteria. Two types of investment criteria can be found: either a LOLE criteria, or a capacity margin criteria, as can be seen in the table below. Some countries do not refer to any investment criteria.

	Type of criteria	Value of criteria
France	LOLE	3 hours/year
Great Britain	-	-
Spain	Capacity Margin	10%
Belgium	LOLE	16 hours/year
the Netherlands	-	-
Germany	Capacity Margin	5% of installed capacity + margin against daily peak load[4] (UCTE criteria)
Austria	Capacity Margin	10% of installed capacity + margin against daily peak load (UCTE criteria)
Switzerland	-	-
Italy	Capacity Margin	18% for the main continent, 30% for Sicily, 80% for Sardinia
Nordel	-	-

Table 3 – Investment criteria used in national security of supply reports, by countries.

The French, Belgian, and Spanish criteria are set by the public authority, and thus are explicitly applied by the TSO. For the Italian criteria, we could not confirm whether it is set by the public authority, or by Terna. Based on their investment criteria, Belgium, France, Spain and Italy also propose an estimate of the system needs of new investment capacity.

Germany and Austria do not have any regulated criteria, but they use the UCTE criteria as an explicit reference for their evaluation of security of supply (UCTE (2007)).

Finally, the Netherlands, Great Britain, Switzerland and Nordel do not use any criteria in their security of supply reports. However we can find some elements on the former criteria used in these countries before liberalisation or on the possible criteria that may be put in place in the future:

- in the Netherlands, generation expansion planning was made on a 10 year horizon, according to a LOLE investment criteria of 2 hours every four years (van Werven et al.,2005). In comparison, Tennet's current LOLE evaluation varies between 30 and 700 hours per year, from today till 2014 (TenneT (2006)). The report compared this range to a "reference value

[4] In UCTE terminology, the margin against daily peak load is the difference between the load at the reference time and the maximum load expected under normal weather and economic development conditions for the year under review (UCTE(2007)).

"of 24 hours per year. The origin of this reference is unclear, as it significantly differs from the historic criteria.

- in Great Britain, the former Central Electricity Generation Board's investment criteria was a capacity margin of 24%. While using the same methodology as before, NGT considers that the improvements in demand and offer forecasts allow to diminish the capacity margin level needed by the system, though it does not refer to any value.
- Switzerland used to apply an old energy balance criteria, requiring that the balance would be at most insufficient for 1 winter in 20, or 5% of the time.
- In Nordel (2007), Nordel also mentions a proposal on the possible implementation of an investment criteria, referring to a loss of load probability (LOLP) of 0.001, i.e. a LOLE of 8.76hours/year, that could be an indicator for triggering corrective measures (" peak load arrangements").

2.2 The treatment of imports and exports in West-Europe TSO's security of supply reports

Originally, the interconnections between West European countries have been built in order to bring mutual assistance in case of serious electricity crisis (based on the principle that a blackout occurring in one country may also have serious consequences in neighbouring countries), and to stabilize the frequency variations on the interconnected system (reducing the consequences of the loss of a generation unit on the frequency and hence on the quality of energy supplied). From a risk analysis point of view, interconnections allow to benefit from the decorrelation between the risk of having a blackout in one country and the risk of having a blackout in one of its neighbouring countries. Indeed, if that country faces serious difficulties to maintain the balance between electricity demand and production, it can call upon its neighbours to temporarily provide additional power through existing interconnections.

The November 4th , 2006 events illustrate this cooperation, since most of Germany's neighbours have quickly modified their production schedule and activated automatic load shedding in order to provide sufficient power to Northern Germany to restore the balance between supply and demand in the region.

The existence of interconnections has favoured the development of long-term commercial contracts between countries. The use of interconnection capacity has also increased since the liberalisation of electricity markets, which encourages the exchange of energy between countries on a short-term horizon. For instance, the implementation of the trilateral market coupling between France, Belgium and the Netherlands is the most recent incentive to do so. Thus today the use of interconnection capacity is more and more intensifying for economic reasons, which in some way can impede the original role of interconnections.

In this context, the preceding analysis should be completed with a specific analysis of the way West European TSOs take into account the participation of interconnections to the system security of supply. We observe that TSOs' methods for taking interconnections into account differ widely across West European countries: while most countries explicitly integrate interconnections to analyse historical power balance, the practices are much more diverse for system adequacy forecasts.

Countries which take into account interconnections in their forecasts

The Netherlands take into account the maximal possible imports in their evaluation of security of supply. Besides since they are highly dependent on imports, TenneT also looks at the way generation capacity evolves in the neighbouring countries, through the UCTE analyses.

In England and Wales, the cross-border capacity from France to England is considered to be available to import in case of a supply and demand disequilibria: it is supposed that the system will be able to import 2000 MW to England during stressed periods. On the contrary, the interconnection to Ireland is considered to be completely used for exportations. The net imports considered in generation adequacy studies amounts therefore to 1.5 GW at peak.

France, Spain and Switzerland take into account long term cross-border contracts for electricity in their analyses, but quite differently. In the Spanish case, REE integrate imports contracts from France in reliable supply at peak. The French TSO prefers to consider that the net French imports are null on peak, cross-border supply contracts from France being compensated by short-term imports. As for Switzerland, available generation capacity is assessed without taking into account its long term contracts noticeably with France because of the risk that cross-border transmission capacity will not eventually be available to transmit the corresponding energy.

Countries which does not take into account interconnections in their forecasts

Two countries, Germany and Austria, assess security of supply without integrating interconnections as if they were isolated systems. In retrospect, it is nevertheless quite clear that these countries mostly import.

Eventually, one can conclude from this comparative analysis of generation adequacy reports that the approaches are highly diversified; it is quite obvious when looking at the planning horizons considered, the indicators used to assess generation adequacy, the reference to a specific planning criteria,(whether this criteria is binding or not), as well as the way interconnections are integrated. This diversity reflects the differences in approaches towards generation adequacy among public authorities in Europe. While such differences may be understandable, they may result in practices that are finally not compatible, which may question generation adequacy at the European level.

In the following paragraph, we focus on two points: the economies of scale that could result from a coherent generation adequacy approach in Europe and the free-rider problem that may emerge in the current context.

3. On the integration of interconnections in the security of supply

Despite the creation of a European electricity market, practices regarding generation adequacy have up to now mainly been national. In other terms, while energy trading tends to be defined at the European scale, planning procedures to ensure generation adequacy and security of supply in real time are still defined at a national scale.

This partial shift towards an integrated electricity market has several consequences. We will first point to the benefits that may result from European cooperation regarding generation adequacy and security of supply; then we will discuss some methods to integrate interconnections in generation adequacy measurement.

3.1. Benefits from cooperation

We have shown in paragraph 2 that generation adequacy policies are currently defined at a national scale with a only a partial European vision. The first consequence is that the potential benefits from interconnection are not exhausted. As pointed out in Helm (2007), “The greater the interconnection, the smaller the required aggregate plant margin – from the portfolio effect - and interconnection brings its own insurance by providing greater resilience to shocks”. The evolution from local to national electricity systems in the twentieth century allowed to optimise electric power generation at a larger scale, which resulted in economies of scale, and we could expect that harmonisation across EU countries would foster a similar evolution. At the origins of the potential economies of scale in a European generation adequacy policy, there is the heterogeneity of interconnected systems in terms of generation as well as in terms of consumption that makes it possible to mutually rely on each other’s capacity margins at least to some extent.

To go into more details, the complementarities in the hazards that affect generation availability and electricity consumption may make it profitable to develop a European vision of generation adequacy and security of supply. Generation adequacy implies indeed that generators have to install enough generation capacity to be able to meet an uncertain demand, taking into account the risks of unavailability of each generation unit due mainly to maintenance and outages. These risks depend obviously on the generation technologies in use in each system - hydro, conventional thermal units, nuclear, wind units…- since the risks that these technologies face are different. They also depend on the structure of consumption: importance of electrical heating, importance of air-conditioning, distribution of electric power consumption among residential consumers, industrial consumers, services…. The larger the scale over which generation adequacy is considered, the more diverse the features of generation units and consumption, and the larger the potential economies of scale.

Let’s illustrate this point with a simple example. We consider two interconnected systems. Each system is characterized by an average margin, consisting of the difference between energy produced by each generation unit and energy consumed by each consumer. The impact of each generation unit on the margin depends on the probability of each unit to be available, i.e. the probability of each unit to be on maintenance, the probability of outage... The probability distribution of generation is then a simple linear combination of the probability of each generation unit to be available. The margin may finally be represented by a probability distribution, considering the probability to be unavailable that affects each generation unit and the anticipated peak power demand. The probability distribution of each generation unit being represented as a binomial distribution with the availability probability as parameter, the margin may be represented by a normal distribution as soon as we consider a sufficiently high number of generation units; its parameters being the average value of the margin and the standard deviation of the margin.

Setting a generation adequacy criteria in this random context implies that investments in generation capacity should be sized such that the margin won't decrease below a certain level more than x % of the time, or equivalently such that the loss of load probability won't exceed a certain level. In other terms, it implies the generation adequacy policy will not cancel the risk of loss of load; it will only limit that risk to a certain extent.

The well-known Markowitz theory (Markowitz (2000)) initially developed in finance showed that an efficient way to manage risk consists in diversifying its assets, each asset generating a yield characterized by an average value and a standard deviation. The relationship between the average yield of a portfolio and its standard deviation is indeed optimised when the portfolio contains assets that have small or null correlations. When we consider generation units that are not or almost not correlated, the standard deviation of capacity margin tends to decrease while maintaining a constant average margin.

Let us consider two interconnected mixed systems, each having thermal and hydraulic power units. System A is characterized by the following elements: standard deviations regarding respectively the thermal and hydraulic power stations :

$\sigma_{th}^{A} = 1.45\ \mathrm{GW}$, standard deviation of thermal power stations

$\sigma_{hy}^{A} = 1.7\ \mathrm{GW}$, standard deviation of hydraulic power stations

$\mu(\mathrm{margin}^{A}) = 8\ \mathrm{GW}$, average of system A's capacity margin

The same way, system B is characterized by :

$\sigma_{th}^{B} = 2.5\ \mathrm{GW}$

$\sigma_{hy}^{B} = 1.2\ \mathrm{GW}$

$$\mu(\text{margin}^{B}) = 32\ \text{GW}$$

If we consider that thermal generation and hydraulic generation are independent variables, then we can compute the average value and the standard deviation of capacity margins in system A and B by applying Markowitz theory:

$$\sigma(\text{margin}^{A}) = (1.45^{2} + 1.75^{2})^{\frac{1}{2}} \approx 2.3\ \text{GW}$$
$$\mu(\text{margin}^{A}) = 8\ \text{GW}$$

$$\sigma(\text{margin}^{B}) = (2.5^{2} + 1.2^{2})^{\frac{1}{2}} \approx 2.8\ \text{GW}$$
$$\mu(\text{margin}^{B}) = 32\ \text{GW}$$

Let us consider that the covariance of the capacity margins of systems A and B amounts to 0.5. Then, mixing the two systems, taking into account their covariance, results in a margin whose average and standard deviation are:

$$\sigma(\text{margin}^{A} + \text{margin}^{B}) = (2.3^{2} + 2.8^{2} + 2 * 0.5)^{\frac{1}{2}} = 3.76\ \text{GW}$$
$$\mu(\text{margin}^{A} + \text{margin}^{B}) = 0.5 * 8 + 0.5 * 32 = 20\ \text{GW}$$

If we now consider the standard deviation of both systems as if there were no complementarities in the hazards that affect each system. In this case, the correlation between the margins is perfect and amounts to 1. :

$$\rho = 1$$
$$\text{cov}(\text{margin}^{A}, \text{margin}^{B}) = \sigma^{A}_{\text{margin}} \sigma^{B}_{\text{margin}}$$

It entails that the standard deviation of the integrated system A + B can finally be calculated as the simple sum of the standard deviations of the margin of each sub-system:

$$V(\text{margin}^{A} + \text{margin}^{B}) = V(\text{margin}^{A}) + V(\text{margin}^{B}) + 2\text{cov}(\text{margin}^{A}, \text{margin}^{B})$$
$$V(\text{margin}^{A} + \text{margin}^{B}) = V(\text{margin}^{A}) + V(\text{margin}^{B}) + 2\sigma^{A}_{\text{margin}} \sigma^{B}_{\text{margin}} = (\sigma^{A}_{\text{margin}} + \sigma^{B}_{\text{margin}})^{2}$$
$$\sigma(\text{margin}^{A} + \text{margin}^{B}) = \sigma^{A}_{\text{margin}} + \sigma^{B}_{\text{margin}}$$

Once applied to the levels that we considered for the margins of system A and system B, we get:

$$\sigma(\text{margin}^A + \text{margin}^B) = 2.3 + 2.8 = 5.1\,\text{GW}$$
$$\mu(\text{margin}^A + \text{margin}^B) = 0.5 * 8 + 0.5 * 32 = 20\,\text{GW}$$

While the average margin is the same, the standard deviation of the margin is much lower in the first case implying that the risk of suffering from power cuts is much lower as illustrated in the following graph. It represents how the probability that the capacity margin, whose mean has been centred around zero, gets higher than respectively –20, -15, …, 15, and 20 GW evolves [5].

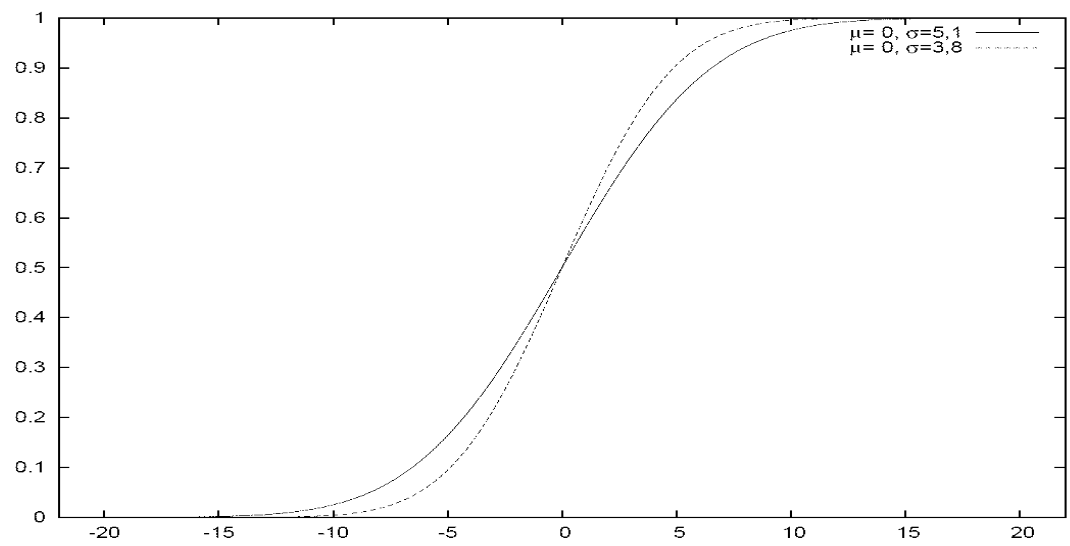

Figure 1 : Cumulative distribution functions for normal variables with the same average μ but different standard deviations σ.

It clearly appears on the graph that the probability to have an average centred capacity margin of -10 GW is close to zero with the smallest standard deviation while it amounts to around 4% with the highest one[6].

The second consequence of this lack of coordination refers to the free-rider problem. It is a classical problem with the provision of public goods (Cornes, Sandler (1986)).

As we have seen in paragraph 2, the methods used by TSOs to assess and control generation adequacy focus on the national scale without any coherent view at the European level. Yet, as shown by some

[5] The mean have been centred around zero on the graph.

[6] Since the average of the margin has been centred around zero, it means that we thus compute the probability to have an average "non centred" capacity margin of 10 GW (-10+20).

recent power failures, power cuts affecting one specific European country may have consequences at a larger scale as soon as the systems are physically interconnected. Some electricity consumers may therefore suffer from power cuts even if the system they are directly connected to is sized to meet a severe generation adequacy criteria as soon as a system that is interconnected could not cope with a unfavourable hazard. Even if its origin does not refer to a problem of generation adequacy but of system operation, the blackout on the 4th November 2006 entailed power cuts that eventually were more important in France than in Germany. Thanks to interconnection some consumers may on the contrary benefit from a risk-adverse generation adequacy criteria in a neighbouring system and have a relatively high level of security of supply without incurring the corresponding investment costs. Creti, Fabra (2007) have developed a stylised model that allow to set the design of capacity markets in such a way that the migration of capacity resources to more profitable neighbouring markets is avoided. In other terms, they analyse a situation where a system benefits from the generation adequacy policy implemented by a neighbouring system to meet its own peak demand.

Let us illustrate this free-rider case with an example.

We consider systems C and D, each being featured by margins which follow normal distributions with the following parameters :

$$\sigma^{C}_{margin} = 4\ \mathrm{GW}$$
$$\mu^{C}_{margin} = 10\ \mathrm{GW}$$

$$\sigma^{D}_{margin} = 3.5\ \mathrm{GW}$$
$$\mu^{D}_{margin} = 20\ \mathrm{GW}$$

Since the average margin of system C is lower than the average margin of system D while its standard deviation is higher, we can infer that generation adequacy in system D is relatively better. It is shown by the computation of the probability that the margins become negatives :

$$P(margin^{C} \prec 0) = \varphi(-\frac{10}{4}) = 1 - \varphi(\frac{10}{4}) \approx 1 - 0.99379 \approx 6.21.10^{-3}$$ [7]

And if we do the same calculation for margin D:

[7] Function φ stands for the cumulative distribution function.

$$P(\text{margin}^{D} \prec 0) = \varphi(-\frac{20}{3.5}) = 1 - \varphi(\frac{20}{3.5}) \approx 1 - 0.9999999944866 \approx 5.5134.10^{-9}$$

If this difference in the levels of generation adequacy, and hence in the probabilities for the customers to be supplied, is due to the fact that public authorities in system D have chosen a stricter criteria for generation adequacy at the system's level, with a specific implementation mechanism, then we face a free-riding problem: in principle, the implementation mechanism chosen - capacity market, public tendering…- ensures that the generation adequacy criteria will be met; it implies that the corresponding investments will be made, their fixed costs being allocated to the consumers connected to system D. Depending on the degree of risk aversion of the consumers and on the weight of these fixed costs, it may happen that these consumers refuse to pay for a security of supply that is finally shared by others. That is the classical problem in economics of free-riding which in the end may decrease the level of generation adequacy that is provided.

To solve this free-riding problem, European member states should design and find an agreement on institutions and policies that create credible incentives for all to cooperate. Even if the European Directive on security of electricity supply and infrastructure investment (Directive 2005/89/EC, European Commission (2006)) might have had this intention, we have shown in the preceding paragraph that in practice, the methods and hypotheses used by TSOs to control generation adequacy are different and not always coherent. Another opportunity to design these credible incentives may be the creation of the European observatory that should be created by the DG Energy to control offer and demand of electricity in Europe.

3.2. Proposal for a measurement method that takes into account interconnection

If public authorities enforce the integration of interconnections in the calculation of capacity margins within countries and enforce this integration in a harmonised way, then it would automatically give a European dimension to security of supply and generation adequacy. As pointed out in Helm (2007), "as interconnection grows, it is important that member states harmonise their approaches to incentivising capacity margins, so that they become fungible".

We briefly sketch out here a method that could be adopted to integrate interconnections[8].

Let's consider two systems, A and B connected by a single line. The cross-border transmission capacity is auctioned through explicit auctions, and the maximum amount auctioned from A to B as well as from B to A is supposed to be X GW : $NTC^{AB} = NTC^{BA} = X$.

The Net Transfer Capacity represents the maximum amount of power that can be physically traded through the interconnection between two systems given security rules related to transmission. This capacity is a deterministic value computed by Transmission System Operators.

Because of the random character of capacity margins, probabilistic methods are relatively well suited to measure loss of load probabilities. The principle is to compare the loss of load probability (or equivalently the generation capacity needed to maintain a positive generation margin x% of the time) for an isolated system with the loss of load probability that is obtained after integration of the cross-border transmission capacity.

Loss of load probability with interconnection

Since the random events that affect power generation and power consumption may be correlated between systems (case of cold spell in western Europe for instance), the loss of load probability in system A not only depends on its capacity margin but also on the capacity margin of the neighbouring systems and on the level of the net transfer capacity between both systems. More precisely, system A can suffer from power cuts in two cases: 1) a first situation where its capacity margin is negative and the interconnection capacity X is insufficient to compensate this lack through imports, and 2) a second situation where its capacity margin is negative, the interconnection capacity X is sufficient to compensate this lack through imports, but the neighbouring systems does not have a sufficient capacity margin to rescue system A.

Loss of load probability of system A with NTC[9]:

[8] This method is derived from the one used by PJM and described in PJM (2005). It is directly derived from the statistical representation of reserve margins that we adopted in the preceding paragraph.

[9] The same computation applies for system B.

$$LOLP_{NTC}^{A} = P((margin^{A} < 0) \cap (X < |margin^{A}|)) + P((margin^{A} < 0) \cap (X > |margin^{A}|) \cap (margin^{B} > -margin^{A}))$$

Loss of load probability in an isolated system

If we now ignore the interconnection and consider an isolated system A, then the loss of load probability is computed as the probability that the system's margin is negative whatever the capacity margin of the neighbouring countries. More precisely:

$$LOLP_{isolated}^{A} = P((margin^{A} < 0) \cap (X < |margin^{A}|)) + P((margin^{A} < 0) \cap (X > |margin^{A}|)) = P(margin^{A} < 0)$$

The benefits from the integration of interconnections in the security of supply is then simply the difference between the two loss of load probabilities:

$$Benefits = LOLP_{isolated}^{A} - LOLP_{NTC}^{A}$$

If the public authorities want to keep a constant loss of load probability, the integration of interconnections makes it possible to replace investments in peaking generation units by imported energy, taking into account the ability of the neighbouring countries to release some excess generation capacity and the limited transmission capacity. The costs associated with the implementation of the generation adequacy policy are decreased accordingly for the consumers.

In its System Adequacy Forecast (UCTE (2007)), the Union for Coordination of Transmission Operators (UCTE) currently takes into account interconnections in its System Adequacy Forecast by identifying whether the observed residual generation capacity of a country is higher or lower than the net transmission capacity; it allows to integrate the effect of limited transmission capacity in energy exchanges in stressed periods. But it does not take into account the complementarities in the hazards that affect generation capacity margins in neighbouring countries. Hence even if interconnection capacities are not binding as regards the capacity required to compensate for an insufficient capacity margin, security of supply may still be endangered if the neighbouring countries do not have simultaneously positive capacity margins. Though it is likely that the implementation of our proposed method in the full European interconnected system would be a challenging task in terms of database building as well as computation, possibilities of improving the UCTE's methodology most certainly exist.

Conclusion

In this paper, we have shown that while generation adequacy criteria were at the core of the management of security of supply in the monopolistic context, their function in a competitive one is more debatable. While some countries continue to rely on such criteria to size their system and guide the now decentralised investment decisions, others do not even mention them and just report on the evolution of supply and demand in a way that is besides more or less detailed and precise. Even in western European systems, we observe a great deal of diversity among the practices, with planning horizons from 3 to 50 years, with evaluation methods that goes from simple deterministic analyses considering capacity margin or/and energy balance to more elaborate probabilistic methods, and with investment criteria that either disappeared with competition or amount to very different levels.

We focus in this paper on the treatment of interconnections in the planning procedures and here also, the hypotheses are diverse and may be incompatible: what happens if France and the Netherlands are at the same time in a stressed situation while their systems have been sized in order to be able to import for the whole interconnection capacity on one side and in order to be more or less self-sufficient on the other side? As highlighted in the Directive 2005/89/EC, the European electricity market requires at least a clear view of the generation adequacy practices adopted at the national scale.

This great deal of diversity in the generation adequacy and security of supply practices may still be problematic. We have shown with simple stylised examples that it does not allow to benefit from the potential economies of scale that would result from a generation adequacy level unified at the European scale. Worst than that, it creates a free-rider problem that may finally result in a lower generation adequacy level for everybody. That is the reason why we suggest to think about methods that would be able to take into account the complementarities in the hazards that affect each capacity margin while considering the structural congestion that affect the European electricity network. Improvements at this level will nevertheless also require cooperation at several levels. It really appears difficult to create an integrated European market without a full harmonization.

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