Electricity Security Across Borders

Case Studies on Cross-Border Electricity Security in Europe

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INTERNATIONAL ENERGY AGENCY

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Introduction

Electricity security[1] is of critical importance to economies around the globe. This issue is only becoming more pressing as jurisdictions seek to decarbonise their power sectors. The increasingly interconnected nature of power markets brings both opportunities to more effectively manage this transition and the challenges that come from increased interdependency. Decisions made in one country can have a profound impact on their neighbours and beyond.

Many recent large-scale blackouts have extended across borders. In August 2003, a blackout originating in the north-eastern part of the United States affected 50 million people across five major jurisdictions[2] and two countries. In September of that same year, 56 million people in Italy, France and Switzerland lost power due to a single failed transmission line. In November 2006, 15 million people across seven European countries lost power because of human error at a single substation.

The benefits of regional integration, however, continue to outweigh the risks. One response to these events has been to increase collaboration across borders.

How best to integrate power systems across borders, though, remains a topic of ongoing discussion. Working across borders often raises questions of responsibility that are hard to answer. Who is best able to plan cross-border transmission lines? Who should bear the cost of their construction? Who should operate them, and how should cross-border power flows be managed? How can jurisdictions work together to ensure regional resource adequacy while also meeting other goals such as decarbonisation? How can the deployment of variable renewable energy (VRE) be coordinated across borders?

The three case studies presented in this report focus on how the European Union (EU) and its member states are working to improve electricity security across borders. The EU's efforts take market integration as the founding principle, with electricity security strongly connected to broader efforts to develop an internal (or single) European energy market. This represents the most advanced effort to date at integrating power markets across multiple jurisdictions, albeit within a region that is already well interconnected.

The case studies are intended to be more descriptive than prescriptive. They will look at the challenges the region faces, some of the ways it has been working to overcome these challenges, and some of the reasons why certain challenges remain unaddressed. In each case, key findings and lessons learned will be highlighted.

What do we mean by "across borders"?

When it comes to evaluating cross-border electricity security, a key question that must be asked is, which borders? In fact, there are a number of borders that are potentially relevant.

As a first step we may consider national borders, which define the limits of domestic political intervention in power systems. In the context of these case studies, they also define the limits of the EU's regulatory remit.

We may also look at technical borders, such as the service territories of the Transmission System Operators (TSOs). For most of Europe, national borders and TSO borders are the same, as most countries have a single TSO. There are, however, exceptions – most notably Germany, which has

[1] Electricity security in this context includes four broad areas: fuel security; resource adequacy; operational security; and governance. This is described in more detail later in this chapter.

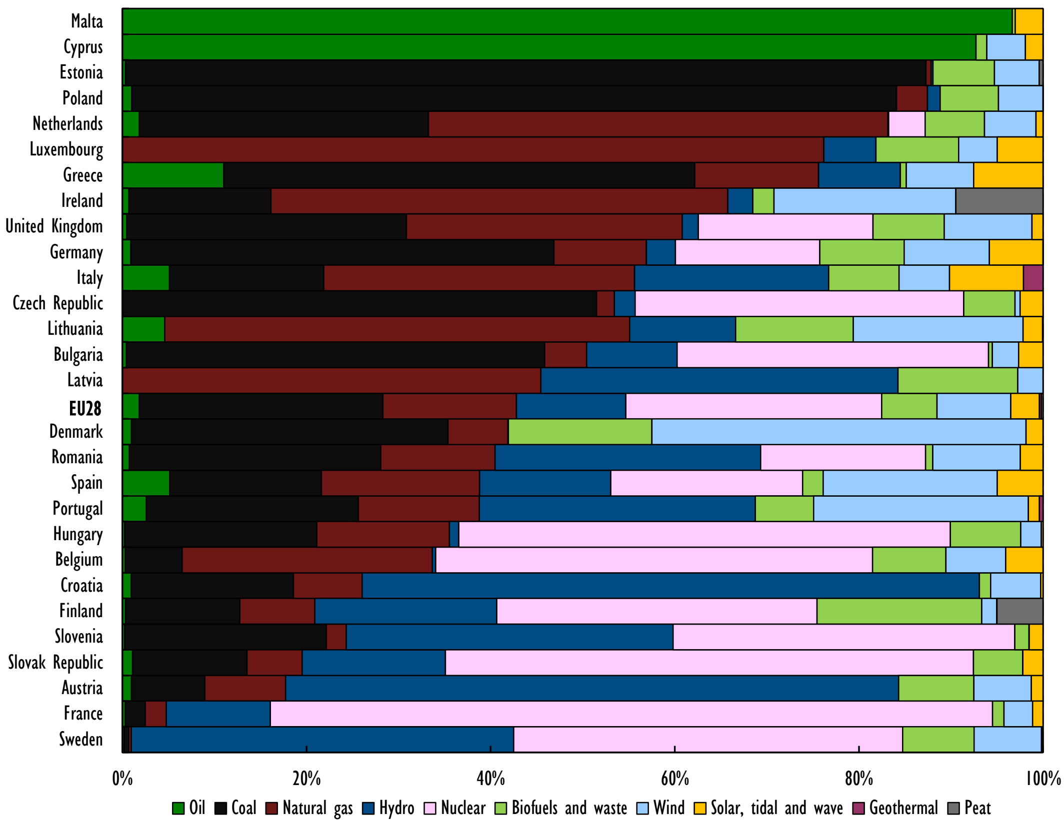
[2] ISO New England, Midcontinent ISO, New York ISO, Ontario, and PJM.

four TSOs. In at least one case (TenneT), a TSO operates in two different countries. Technical borders may also be defined by transmission constraints (which may exist within or between countries).

All of these borders, and many others not mentioned, are relevant to the topic at hand. The primary focus of this study, however, will be on *jurisdictional* borders. By this we mean the boundaries of decision making. This includes both borders across which decision making authorities are clearly defined, and borders for which the decision making authority is at times less clear. In practice, different kinds of jurisdictional borders may overlap with one another, though in Europe they tend to be more distinctly defined than in, for example, the United States, where you have many different overlapping jurisdictional boundaries (for example, the regions defined by the North American Electric Reliability Corporation (NERC) as compared to the Regional Transmission Operator (RTO) regions). Focusing on jurisdictional boundaries allows for the examination of many different types of borders through a common lens.

Overview of the case studies

Figure ES.1 • Electricity generating mix for the EU-28[3]



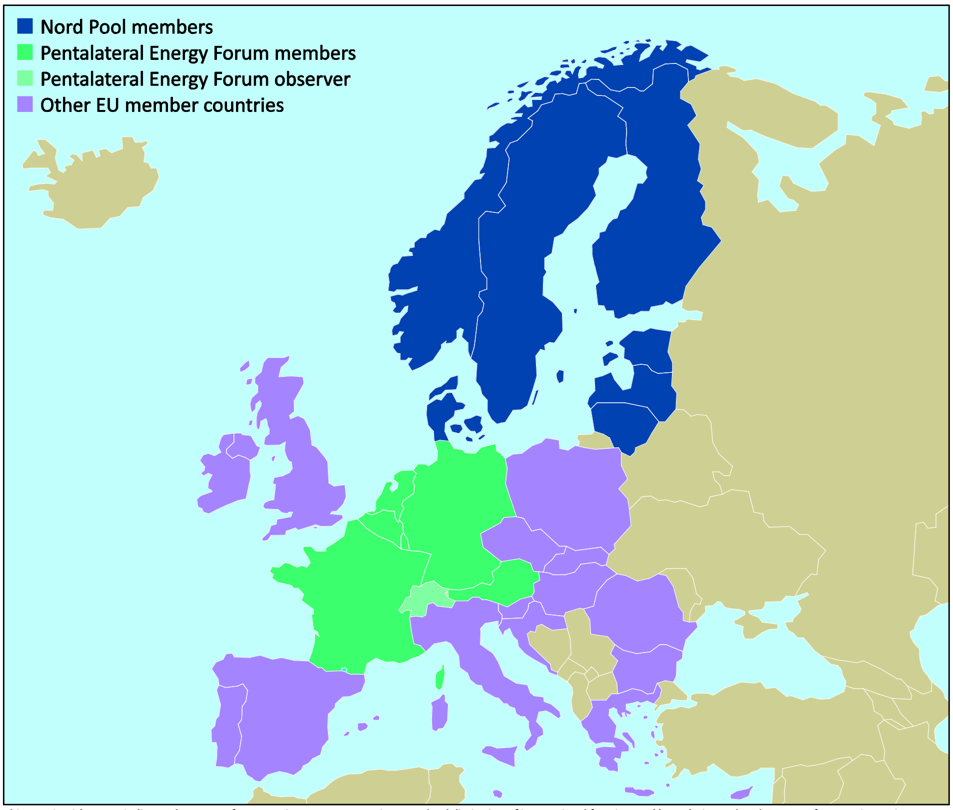
Sources: IEA (2016) (Electricity Information), Energy Balances of OECD Countries, OECD/IEA, Paris; IEA (2016), Energy Statistics of Non-OECD Countries, OECD/IEA, Paris.

[3] Two footnotes: 1. **Footnote by Turkey**: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, Turkey shall preserve its position concerning the "Cyprus issue". 2. **Footnote by all the European Union Member States of the OECD and the European Union**: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

The EU has one of the largest and most interconnected power systems in the world. However, its 28 member states are diverse in many ways, not the least of which is diversity of the generating fleet (Figures ES.1). From diversity, however, comes strength. High levels of interconnection across member state borders make it possible to leverage this diversity to make the EU power system as a whole more efficient, and to improve overall electricity security. This has also made it possible to go further than in many other parts of the world in terms of the integration of electricity markets and, in some countries, has helped to enable the integration of high shares of VRE generating technologies.

Power system integration and, in particular, the ongoing development of the EU Internal Energy Market (IEM), is both supported by and in tension with the institutional arrangements of the EU and its member states. The various treaties that define the EU set limits on its remit and authority, determine the structure of its institutions, and inform the way it interacts with its member states. The member states themselves interact with each other based not only on the EU framework that they all follow, but also but reflecting geography and historical relationships. Given the topic's complexity, this report focuses on three case studies: one on the EU's governance framework for electricity security and the relationship between it and the various member states; one on a regional collaborative effort in Central-Western Europe, the Pentalateral Energy Forum (PLEF); and one on the Nordic countries and the development of the Nord Pool spot market[4] (Figure ES.2).

Figure ES.2 • The EU, the Pentalateral Energy Forum, and Nord Pool member countries



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

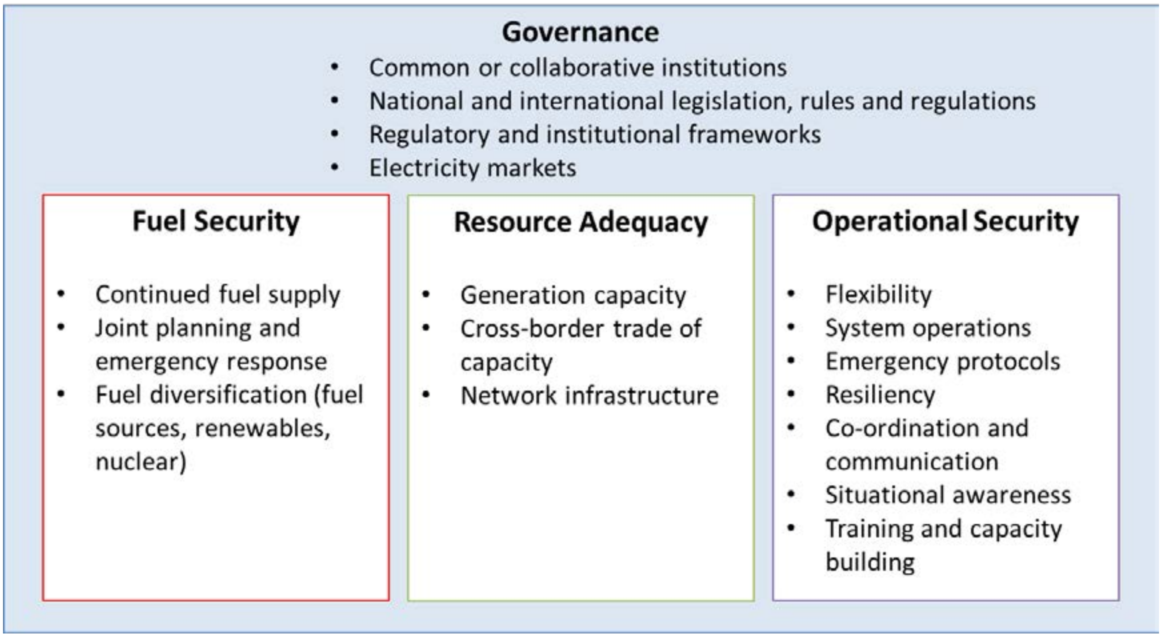
[4] Though the Nord Pool spot market includes the three Baltic States, much of the historical context for its development is tied intimately to Nordic cooperation. Therefore, much of the Nord Pool case study will focus on the Nordic region.

Extending the Electricity Security Assessment Framework "across borders"

The IEA's Electricity Security Assessment Framework is an integrated approach to evaluating a single jurisdiction's efforts to meet its electricity security goals. Although developed with a particular focus on national electricity security, much of it is relevant to regional electricity security as well. The framework has been extended to better capture these elements, as well as other aspects of electricity security critical to regional electricity security.

The framework has three pillars: fuel security; resource adequacy; and operational security. Underpinning each of these pillars is governance, which addresses many topics beyond electricity security but which also influences each of the three pillars in their own right. Governance must therefore be analysed both as a distinct entity and through each of the three pillars (Figure ES.3).

Figure ES.3 • Outline of the Electricity Security Across Borders Assessment Framework



The Assessment Framework also considers these areas in two different temporal dimensions: short-term (i.e. the ability to maintain system reliability and respond to emergencies) and long-term (i.e. the ability to meet long-term resource adequacy needs).

The case studies included in this report focus on three areas across both the short-term and long-term time horizons: governance; resource adequacy; and operational security. While fuel security is a critical component of regional electricity security, and is certainly an area of concern within the EU, evaluation of cross-border fuel security issues has already been done to a large degree by other IEA publications, in particular those on gas security. It remains relevant to the topic at hand, however – for example, one of the perceived benefits underpinning national RE targets is improved fuel security. Fuel security will therefore be discussed to a limited degree where relevant.

The sections on governance detail the institutional frameworks and various authorities that allow for EU-wide and regional collaboration. For the EU, this means looking at relevant legislation and the roles and responsibilities of the various institutions. For the PLEF and Nord Pool – both of which are bottom-up, collaborative bodies – it means looking at membership, institutional arrangements, and, where relevant, founding documents.

The sections on system security examine the various ways countries are collaborating to ensure efficient and secure cross-border operations and trade. For the EU, this means looking at the development of Network Codes and Guidelines which seek to harmonize many operational issues across the continent. We also look at how some EU institutions are evolving to play a more active role on cross-border issues. For the PLEF, this section looks at the development of market coupling[5], an innovation of the PLEF members that has been adopted by the EU as the standard method for cross-border integration. For Nord Pool it means looking at the development and functioning of the regional wholesale market.

Finally, the sections on resource adequacy look at how each country and the EU as a whole are approaching the question of long-term electricity security. For the EU, the focus is on transmission planning and development, national policies that impact the generation mix, and the development of capacity mechanisms (CMs) in some member states. For the PLEF, the focus is on the development of a regional resource adequacy assessment. For Nord Pool this means looking at coordination among member countries, a closer look at the development of resource adequacy in the region, and the integration of the Baltic States into the Nord Pool market.

Key findings

- **The history of cross-border electricity security cooperation in Europe extends back decades, and is founded on technical regional collaboration, in particular related to the sharing of generating reserves.** Collaboration on electricity security of supply has evolved into cross-border trade of electricity.
- **Recent collaboration has focused on the harmonisation of the various regional efforts into a common framework for Europe.** Electricity security, however, remains a core competency of member states rather than of the common EU institutions, and market design efforts – much of which address greater regional integration and increasingly the integration of large shares of VRE into the power system – reflect this fact.
- **The tools that the EU employs to increase overall electricity security and develop the IEM are driven by the nature of the EU's treaty relationship with its member states and, therefore, are in many ways unique to the EU context.** The distribution of responsibilities on energy between the EU and the member states has led to a combination of top-down and bottom-up approaches to developing the IEM and improving cross-border electricity security.

Case study 1 (EU)

- **The EU has made significant progress in its efforts to develop the IEM.** In particular, the development of Network Codes and Guidelines, despite delays, seems on track despite a relatively short timeline for implementation.
- **Many topics directly relevant to cross-border electricity security and the IEM remain the competence of the 28 member states, but one of the primary tools the EU has at its disposal is the ability to support the development of cross-border interconnectors.** This and a related programme for financing infrastructure Projects of Common Interest has, therefore, become a key tool for the EU to influence electricity security policies more broadly.
- **Continuing lack of coordination on some key national policies nonetheless has significant cross-border impacts, affecting both operations and resource adequacy.** National RE targets and support schemes have resulted in the rapid deployment of VRE, leading to spill over effects such as increased loop flows through the grids of neighbouring country. National phase-out policies for nuclear and coal power are raising resource adequacy questions. At the

[5] This is sometimes also referred to as "price coupling of regions", or PCR.

same time, EU member states continue to prefer to meet domestic adequacy needs with domestic capacity, despite the availability of cross-border interconnectors.

Case study 2 (PLEF)

- **The PLEF is made up of well interconnected systems where cooperation is critical to maintain electricity security.** It has provided a forum for governments, TSOs and market participants to collaborate to improve electricity security and manage their rapidly changing power sectors, in particular the impacts of higher penetration of VRE.
- **This bottom-up approach to collaboration has proven capable of leading to meaningful market reforms and improvements in regional security.** Although the work of the PLEF does not carry legal force, many of its outputs have led to the adoption of reform policies by its membership. The PLEF has also allowed Switzerland, a non-member country, an opportunity to engage with EU member countries on critical electricity security issues.
- **The PLEF has set an example for the rest of the EU, acting as a laboratory for reform and innovation.** Concepts first developed by PLEF members, such as market coupling and regional resource assessments that include probabilistic analysis, have now also been adopted at the EU level.
- **Although close collaboration among the PLEF members has yielded many notable successes, disagreements remain on how to address some aspects of electricity security and market design.** PLEF countries have differing views on the need for capacity mechanisms or how to develop cross-border balancing markets. The PLEF, in its present form, may not be able to fully resolve these differences.

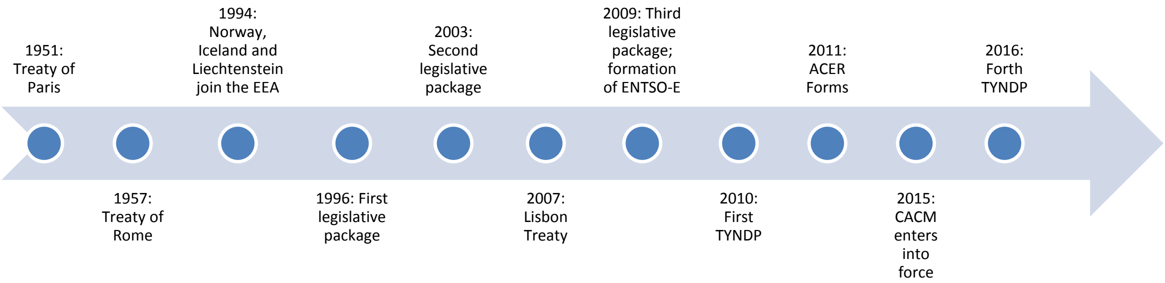
Case study 3 (Nord Pool)

- **Nord Pool is the most advanced cross-border power market in Europe.** Developing such an integrated market requires significant levels of collaboration and trust. In the Nordic region, this trust builds on a long history of collaboration on a wide range of policy questions.
- **Though well integrated, the Nord Pool member countries do not make up a truly regional power system.** TSOs remain national, and though there is extensive collaboration at a technical level, decision making and planning continue to be bottom-up processes. For example, capacity mechanisms, where they have been implemented, are country-specific.
- **Nord Pool has proven flexible enough to expand beyond its core Nordic country base through the inclusion of three Baltic Sea countries, and to respond to EU regulations.** In many ways, Nord Pool has been a leader in the conversation on market design and cross-border issues.

Case Study 1: Electricity Market Integration and Security in the European Union

At the heart of the European Union's integration project between 28 nation states is the aim to create a single (or common, or internal) market across the whole continent of Europe, allowing for the free movement of goods, capital, services, and people. From the formation of the European Coal and Steel Community under the Treaty of Paris (Figure 1.1) to the Lisbon Treaty (2007) these 'four freedoms' are the building blocks of the EU.

Figure 1.1 • Key events in the history of the European Union



Of the EU's various common market initiatives, the twenty-year effort to create the IEM is relatively recent. Despite that, significant progress has been made, and while the IEM remains incomplete, the path towards the creation of a single IEM is clearer now than at any point in the past. This focus on market integration, however, has not been matched by an equivalent policy ambition on electricity security.

The EU's desire to achieve a single market in energy must be balanced against the fact the EU member states retain authority to decide on their national energy mix, and their desire to maintain control over domestic energy security. As a result, the EU has taken a 'market first' approach, with security tied to market integration as an additional benefit. This is quite different than the approach taken, for example, by the United States, which does not have a common market framework for electricity, but which does have an institution responsible for developing common security standards, namely, the North American Electricity Reliability Corporation, or NERC.

There is no organisation equivalent to NERC in Europe. Security has, however, been addressed to some degree by the European Commission in the 2005 Security of Electricity Supply Directive (see Box 1.1), and there are discussions on how a more comprehensive framework could be defined. In particular, any such framework would likely include a focus on cross-border grid interconnection, the impact of increasingly decentralised operations and higher shares of VRE, the risk of cyberattack, and a "shared responsibility" among the EU member states for a "joined-up approach to electricity" (EC, 2016a).

This case study looks at the various ways that the EU institutions and the member states work together – or separately – on maintaining electricity security across numerous and varied jurisdictional boundaries.

Key findings

- **The EU has made significant progress in its efforts to develop the IEM.** In particular, the development of Network Codes and Guidelines, despite delays, seems on track despite a relatively short timeline for implementation.
- **Many topics directly relevant to cross-border electricity security and the IEM remain the competence of the 28 member states, but one of the primary tools the EU has at its disposal is the ability to support the development of cross-border interconnectors.** This and a related programme for financing infrastructure Projects of Common Interest has, therefore, become a key tool for the EU to influence electricity security policies more broadly.
- **Continuing lack of coordination on some key national policies nonetheless has significant cross-border impacts, affecting both operations and resource adequacy.** National RE targets and support schemes have resulted in the rapid deployment of VRE, leading to spill over effects such as increased loop flows through the grids of neighbouring country. National phase-out policies for nuclear and coal power are raising resource adequacy questions. At the same time, EU member states continue to prefer to meet domestic adequacy needs with domestic capacity, despite the availability of cross-border interconnectors.

Governance

Overview of relevant EU legislation and regulations

Treaty on European Union and the Energy Union

The first section of the Lisbon Treaty, or the 2007 Treaty on the Functioning of the European Union (TFEU), sets out the shared and separate tasks of the EU institutions and the 28 member states, and establishes key aims for major policy areas. Energy is generally a shared competence of the EU and the member states. In some cases, though, energy policies are also made by EU institutions that cover areas only tangentially related to energy, such as competition, trade, and climate change. In those cases, the EU has exclusive competence. This has to a significant degree shaped the way the EU has addressed energy policy broadly. For example, member states have explicit control over their own energy mix, while the EU has authority over market integration.

TFEU Article 194 provides that EU energy policy 'in the context of the establishment and functioning of the internal market and with regard for the need to preserve and improve the environment' shall aim: 1) to ensure the functioning of the energy market; 2) to ensure security of energy supply in the EU; 3) to promote energy efficiency and energy saving and the development of new and renewable forms of energy; and 4) to promote the interconnection of energy networks.

EU legislation mainly takes the form of either Regulations or Directives. EU Regulations are directly applicable and binding in all member states; Directives are framework legislation which member states are required to implement by means of national action. A major policy package will often consist of Directives setting major objectives and Regulations for more technical aspects. Most legislation is adopted through co-decision of the European Parliament and the Council of member states; Regulations can be adopted under various procedures, including by experts representing the member states (in a process referred to as "comitology").

The European Commission – the executive body of the EU – drafts legislation and monitors its application. It is made up of 28 politically appointed Commissioners who lead some 40 policy and administrative departments including a Directorate-General for Energy. The European Court of

Justice is the highest court in the EU in matters of EU law and is the ultimate enforcer of legislation.

In 2015, the EU consolidated existing energy policy and future energy goals into a new Energy Union plan for 'secure**,** affordable and climate-friendly energy for EU citizens and businesses' (EC, 2016b). The Plan emphasises free flow of energy across national borders within the EU, leadership in renewable energy production, and speaking with a single voice on global energy matters.

EU legislation and the Third Internal Energy Package (Third Package)

The development of an internal (or single) market in electricity has been an EU policy priority for twenty-five years. To harmonise and liberalise the EU energy market, three consecutive packages of legislation were adopted between 1996 and 2009, addressing market access, transparency and regulation, consumer protection, interconnection, and adequate levels of supply.

Regarding electricity, the key internal market legislation in force today includes:

- Directive 2005/89/EC concerning measures to safeguard security of electricity supply and infrastructure investment (Security of Electricity Supply Directive, see Box 1.1).
- Common Rules for the Internal Market in Electricity Directive (2009/72/EC) ("Electricity Directive").
- Regulation on Conditions for Access to the Network for Cross-Border Exchanges in Electricity (714/2009/EC) ("Electricity Regulation").
- Regulation Establishing an Agency for the Cooperation of Energy Regulators (713/2009/EC) ("ACER Regulation").
- Regulation on Wholesale Energy Market Integrity and Transparency (1227/2011/EU) ("REMIT Regulation").

The Third Internal Energy Market package (2009) came into effect in 2011 and covers five main areas:

- Unbundling energy suppliers from network operators.
- Cross-border cooperation between transmission system operators and the creation of European Networks for Transmission System Operators (for electricity, ENTSO-E and for gas, ENTSO-G).
- Strengthening the independence of national regulators.
- Establishment of the Agency for the Cooperation of Energy Regulators (ACER).
- Increased transparency in retail markets to benefit consumers.

Overall, the IEM project has both harmonised and deregulated the European electricity market, removing barriers to trade, unbundling generation and transmission, and enabling new suppliers to enter member states' markets and consumers to choose among suppliers. Common standards in environmental and safety regulations and improving the security of supply by facilitating the development of trans-European networks have been secondary but important aims.

Box 1.1 • Directive 2005/89/EC and the Security of Electricity Supply framework

The TFEU introduced an explicit EU competence on energy policy in European primary law beyond already existing intervention rights on environmental, competition and internal market grounds, but does not affect the right of each member state to determine their own energy mix. (The same is true for North America, where each US state and Canadian province maintains decision-making power on its energy supply).

Within the EU legal framework, security of electricity supply is governed in general by the rules of the Third Package and in particular by the special requirements of the Security of Electricity Supply Directive concerning measures to safeguard security of electricity supply and infrastructure investment.

The Electricity Directive allows member states to impose public service obligations for security of supply on operators. Member states also have the right to take safeguard measures in crisis situations, so long as these do not disturb the functioning of the internal market and are notified to other member states and the Commission.

The Security of Electricity Supply Directive further requires member states to ensure that TSOs set minimum operational rules and obligations for network security, and that they consult with the relevant actors in countries with which there is interconnection, but leaves it to member states to set their own rules with regard to the content of these operational procedures and obligations.

Source: Adapted from IEA, 2014a

The European Commission publishes an annual progress report on the IEM and the implementation of EU law. At the time of writing, the most recent report available is for 2014 (EC 2014a). In 2011, a deadline was set to complete implementation of the Third Package by the end of 2014, with Heads of Government underlining that no EU member state should remain isolated from European gas and electricity networks after 2015. This deadline has not been fully met. Delays in national implementation and market harmonisation are now subject to infringement procedures by the Commission, and more investments are needed in transmission (in particular, in the Iberian Peninsula, the Baltic region, and between Ireland and the United Kingdom[6]).

A further legislative package ("Winter Package") is expected to be proposed by the European Commission at the end of 2016, to address retail consumer empowerment and provide for some re-design of the energy market in line with decarbonisation. Proposals to remedy "clear gaps" in the legal framework provided by the Security of Electricity Supply Directive are also being considered by the Commission. This is discussed in more detail below.

Box 1.2 • EU enlargement

Although the EU has made steady progress in its efforts to implement the IEM, much work remains to be done. In particular, implementation of the Third Package remains uneven. This is especially true for countries that have only recently joined the EU.

Between 2004 and 2013, the EU expanded its membership from 15 member states to 28. Nearly all of the 13 additional members are located in Eastern Europe. In many of these states the incumbent supplier remains dominant and the independence of the regulator is limited. The region as a whole

[6] At the time of writing it is unclear when, or on what terms, "Brexit" – the exit of Britain from the EU following the UK's referendum on 23 June 2016 – might take place. Basic details are unlikely to be known before 2019 at the earliest (two years after the first possible date for the opening of exit negotiations between the UK and the other 27 EU member states), with the full implications for the UK's relationship to the internal energy market taking still more time to emerge. The experiences of Norway (Case Study 2) and Switzerland (Case Study 3) may offer some insights. It would be premature, however, to draw any explicit parallels.

remains relatively isolated from the rest of Europe, and within the region harmonisation of trade and network operation rules has proven difficult.

This is not to say no progress has been made. Liberalisation of markets has been fully achieved in a number of these countries. The Czech Republic, Hungary, Romania and Slovakia have coupled their day-ahead wholesale markets, and the Baltic States have joined Nord Pool (Case Study 3). This region is also set to receive a significant amount of investment in cross-border interconnections under the EU programme of Projects of Common Interest.

Source: IEA 2014a, EC 2014c

Market restructuring (unbundling)

Unbundling separates energy supply and generation from the operation of transmission networks, in order to ensure fair access to infrastructure for all market participants. Though electricity security is not, itself, a motivation for market restructuring, the nature of the unbundling process can have implications relevant to the topic of cross-border electricity security. In particular, unbundling has a direct impact on who makes future investment decisions and who is responsible for maintaining security of supply.

Under the Third Package, unbundling must take place in one of three ways, depending on the preference of individual member states:

- Ownership Unbundling (OU): integrated energy companies sell off their electricity networks. In this case, no supply or production company is allowed to hold a majority share or interfere in the work of a transmission system operator.
- Independent Transmission Operator (ITO, or exceptionally a variant termed ITO+): energy supply companies may still own and operate electricity networks but must do so through a subsidiary, and important decisions must be taken independently of the parent company.
- Independent System Operator (ISO): energy supply companies may still formally own transmission networks, but must leave operation, maintenance, and investment in the grid to an independent company.

In each case the party that makes investment decisions varies. Under the OU model, generation and transmission ownership are explicitly separated, and the transmission owner has full control over both investment and operating decisions with regard to the network. Under ITU, a single company may own both transmission assets and generating assets, but market rules are in place in order to ensure independence and open access. Finally, under the ISO model, ownership and operation of the transmission grid are completely separated, and therefore investment and operating decisions are also taken separately.

Different options have been chosen by different companies and countries. For example, Germany and the United Kingdom (UK) contain a mix of OU and ITO. Denmark and Spain use OU, while France uses ITO. The least prevalent option is ISO. This is in contrast to the United States, where the ISO model is more widely used (Box 1.3).

Box 1.3 • ISOs in the United States

The term ISO is also widely used in the United States. While similar, there are differences between the ISO as set out in the EU legislation and the definition of the ISO as it is applied in the US. In the US the ISO is not explicitly defined. Instead, FERC Order 888 lays down a set of guiding principles. These principles include: operating under rules that are fair and non-discriminatory; not having financial interest in or conflict of interest with any power market participants; open access under a single tariff; transparency; and explicit control over the interconnected transmission system in its service territory (FERC, 1996). The guidelines also state that the ISO has primary responsibility for ensuring short-term electricity security, and that its reliability standards should comply with NERC standards.

In practice, the responsibilities of the ISO in Europe and the US have significant overlaps. The critical difference between a US ISO and an EU ISO is that, in the US, the ISO is also responsible for forming the wholesale market; in the EU, this is done through power exchanges. Moreover, in the US unbundling is not universal and, even in states that have unbundled, utility participation in an ISO is often discretionary. States may therefore contain a mix of utilities that operate within and outside an ISO, while some states may have some utilities that are members of one ISO and other utilities that belong to a second ISO (e.g. Illinois, parts of which are served by the Midcontinent ISO and by PJM).

In addition to the ISO, the US also has the concept of the Regional Transmission Operator (RTO). The guiding principles for the RTOs are defined in FERC order 2000. These are similar to the guiding principles for the ISO, and in essence allow for the creation of other organisational structures that provide equivalent levels of independence and open access. The difference between ISO and RTO is so subtle, however, that the two terms are often used interchangeably.

The European Commission publishes guidance documents explaining how these unbundling models should be applied by the National Regulatory Authorities (NRAs), and also provides its opinion on the certification procedure. Operators that comply with the unbundling rules can apply for national certification, and every operator in Europe must be certified.

The Electricity Target Model and Developing EU-wide network codes

Alongside the IEM packages, starting in 2006 the European Regulators Group for Electricity and Gas (ERGEG), an advisory group created by the Commission in 2003, worked to develop “bottom up” voluntary market integration through Electricity Regional Initiatives among NRAs, TSOs and electricity market participants. This informal work was incorporated into the Third Package as the legally binding EU electricity target model, defining priority areas of wholesale market harmonisation to be taken forward by means of minor regulations and advisory instruments. ERGEG has since been replaced by ACER and the Council of European Energy Regulators (CEER).

There are four target models for electricity. Three are set out in the Framework Guideline on Capacity Allocation and Congestion Management (CACM) for Electricity, published in 2011 by ACER and which came into effect in 2015. These set out methods for allocating capacity in day-ahead and intraday[7] timescales, and outline the way in which capacity is to be calculated across different network zones. The fourth target model relates to balancing.

The day-ahead and intraday target models support a wider goal of market coupling. Market coupling is the process by which wholesale electricity markets are joined across jurisdictional borders through the sharing of data and the use of common algorithms. The process is managed by the grid operators and power exchanges from the relevant member states, with the ultimate aim of managing cross-border electricity flows in an optimal way and smoothing out price differences across the EU. The first region to couple its (day-ahead) markets was Central West Europe (CWE), through the Pentalateral Energy Forum (PLEF, Case Study 2). North West Europe (NWE) and South West Europe (SWE) followed in 2014, while another market coupling effort was launched among the Czech Republic, Hungary, Romania and Slovakia.[8] Italy and Slovenia coupled their markets in February 2015. The process culminated in May 2015 in the further coupling of the SWE and NWE regions.

[7] The intra-day market allows market participants to bid in the period between the day-ahead market (24 hours ahead of delivery) and the real-time, or balancing, market.

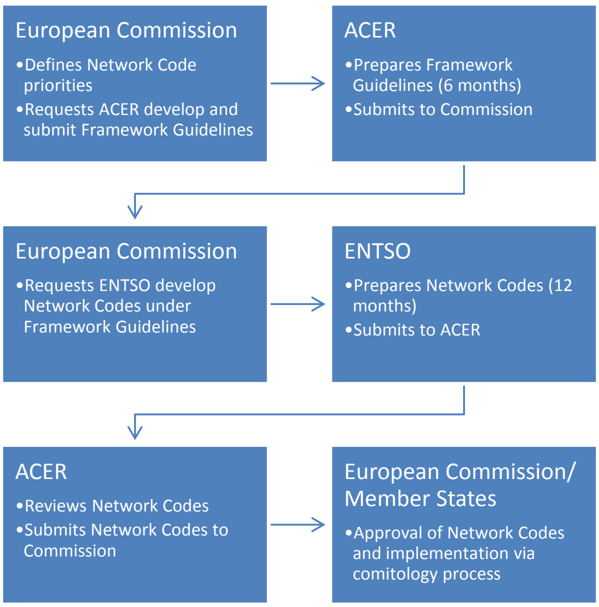
[8] The Czech Republic has noted to the authors that this project has increased liquidity, efficiency, and social welfare among the coupled markets.

At the same time, a new flow-based method for market coupling was introduced in Central West Europe to better account for renewable power flows in integrated cross-border electricity networks. The cross-border capacity between Germany-France and Belgium-France has increased in 2016 following the implementation of flow-based market coupling in 2015.

To achieve these targets and deliver the Framework Guidelines, the Third Package established a mandate and process to develop detailed European Network Codes and Guidelines. The aim was to implement common technical and commercial rules governing access to energy networks, create a level playing field among market actors, and remove barriers to trade between member states.[9] Article 8(6) of the Electricity Regulation provides that Framework Guidelines and Network Codes be adopted for:

- Network security including transmission reserve capacity for operation network security.
- Network connection.
- Third-party access.
- Data exchange and settlement.
- Interoperability.
- Operational procedures in an emergency.
- CACM, including intraday and day-ahead as well as long-term capacity.
- Trading with regard to technical and operational provision of network access services and system balancing.
- Transparency.
- Harmonised tariff structures, including locational signals and inter-transmission system operator compensation.
- Energy efficiency regarding electricity networks.

Figure 1.2 • Process for developing network codes



Source: ACER

[9] Network codes and network guidelines are both legally binding, but their adoption is managed under different provisions of the EU's regulation on electricity.

Ultimate responsibility for the text and content of the Network Codes lies with the Commission. Draft Codes are prepared in an iterative exchange between ACER and ENTSO-E, and then submitted to the Commission for adoption as legislation (under a comitology process by the Electricity Cross-Border Committee, made up of specialists from national energy ministries). At each stage, except comitology, stakeholder consultation is required. Once adopted, European Network Codes become annexes to the Electricity Regulation and take precedence over national legislation, licences and domestic industry codes, which may need to be amended.

Considerable progress has been made on the Network Codes, given the relatively short timeline within which they have been developed. Nevertheless, the experience has highlighted the complexity of the EU market harmonisation task across different national and regional electricity systems that initially evolved under separate jurisdictional frameworks in order to achieve wholly nationally-defined interests. Some Network Codes have been slower and more contentious to prepare than others:

- European Network Codes for electricity currently in force are CACM, Demand Connection, Forward Capacity Allocation, HVDC, and Requirements for Generators.
- Substantially finalised and awaiting entry into force: System Operators.
- In process: Electricity Balancing; Emergency and Restoration.[10]

The Network Code on Emergency and Restoration deals with procedures to be followed during emergencies, blackouts and restoration, including *ex ante* plans for system defence and system re-synchronisation, information exchange and incident analysis.

Meanwhile, Regional Initiatives continue as a complementary process to the Framework Guidelines and Network Codes, enabling pilot testing of provisions and early implementation (Case Study 2 and Case Study 3).

Some participants in the Network Code development process – in particular, smaller participants who are more resource constrained – have complained about the Codes' size and complexity. While the process for providing comments is viewed as open and inclusive, in practice stakeholders (mainly, though not only, stakeholders with limited staff or technical capacity) are unable to fully follow the details of the Codes as they are developed. As a result, some sections of the Codes have likely received relatively less scrutiny.

This is a concern in particular for participants in those markets that have moved further along in the process of liberalisation and market integration than others. For example, the Nordic markets have already created a common market in the form of Nord Pool (Case Study 3). For parties in such regions, there is some concern that the process of creating common Network Codes could result in a set of "lowest common denominator" regulations which would potentially undermine existing regional efforts at market integration by requiring them to alter specific market rules to accommodate the broader IEM.

EU electricity interconnection target

In October 2014, the EU heads of government called on all member states to achieve sufficient interconnection by 2020 to allow at least 10% of domestic generation to be transported across their borders. Twelve member states do not currently meet this target: Cyprus, Estonia, Italy, Ireland, Latvia, Lithuania, Malta, Poland, Portugal, Romania, Spain and the UK.

[10] See https://ec.europa.eu/energy/en/topics/wholesale-market/electricity-network-codes, http://www.acer.europa.eu/en/Electricity/FG_and_network_codes/Pages/Background-and-timeline.aspx and https://www.entsoe.eu/major-projects/network-code-development/updates-milestones/Pages/default.aspx

In its State of the Energy Union report of February 2015 the European Commission proposed a new interconnection target of 15% for 2030. This 15% target is constrained, however, by the fact that interconnectors should pass a cost-benefit test, and it is not clear, *a priori*, that a 15% target for the EU as a whole is consistent with such a test. The Commission therefore intends to report before the end of 2016 on progress towards the completion of a list of the most vital energy infrastructures and on the necessary measures to reach that target.

The primary tool for meeting this target is the Trans-European Networks (TENs) strategy providing for the selection of EU Projects of Common Interest (PCIs).[11] Once selected, PCIs benefit from accelerated licensing procedures, improved regulatory conditions, and some access to financial support. The Commission has emphasized that obstacles and delays to infrastructure permitting are a major factor holding back interconnection. These arrangements remain limited to PCIs, however, so only projects categorized as PCIs will benefit from these rules. Moreover, there is no enforcement of an accelerated permitting 'one-stop shop' approach in member states.[12]

Roles and responsibilities with regard to electricity security

National institutions

National institutions retain default individual responsibility for electricity policy, including security, wherever treaties or legislation have not assigned this to the EU level. TFEU Article 194 also provides that EU legislation 'shall not affect a member state's right to determine the conditions for exploiting its energy resources, its choice between different energy sources and the general structure of its energy supply'.[13]

In 2010 the Commission carried out an evaluation of the Security of Electricity Supply Directive resulting in a report on implementation (EC, 2010). This showed that member states had properly implemented the Directive, but it also identified gaps in the framework which have allowed different and uncoordinated national policy approaches to persist. It also recognised that new challenges – notably in cybersecurity – have emerged since the adoption of the Directive in 2005. The Commission now intends to prepare new proposals to address two key problems:

- Different national rules and procedures that hamper security of supply, for instance divergent approaches by member states on which conditions require the suspension of normal market and system operation activities.
- Insufficient cross-border co-operation and joined-up action by national authorities, for instance the absence of clear roles and responsibilities of national authorities in relation to the risk that under-protection in some member states could have spill-over effects for neighbouring countries.

Among options that the Commission is considering are new or amended legislation to coordinate national rules and requirements at regional and/or EU level, including an obligation to assess risks at a regional level and draw up risk preparedness plans in a regional context (perhaps with mandatory peer review of national plans by regional neighbours). A stronger mandate for the Electricity Coordination Group might be a way to introduce peer review. The Commission will also look at possible IT solutions to facilitate cooperation among the relevant authorities (EC, 2016a).

[11] In addition to transmission, PCIs may be electricity storage, power substations, and phase-shifters. The effort to synchronise the Baltic system to the rest of the EU is also classified as a PCI.

[12] For more, see section on Projects of Common Interest, and Box 1.4, below.

[13] This article causes some controversy in the context of climate change policy, with, for example, Poland using it to defend its coal industry in opposition to EU institutional views on the matter.

National regulatory authorities (NRAs)

The Third Package requires each member state to designate a single NRA. Member states may also retain other regulatory authorities for regions within the country, but there must be a senior representative at the national level. The NRA must be able to carry out its regulatory activities independently from government and from any other public or private entity.

NRAs have eight general objectives and 21 specific duties (Electricity Directive, Articles 36 and 37(1)). These duties include: monitoring compliance with and reviewing the past performance of network security and reliability rules, and setting or approving standards and requirements for quality of service and supply.

NRAs are given information rights and investigative and enforcement powers in line with internal energy market objectives. In the UK, for example, the national regulator OFGEM is required to carry out its functions under the (national) Electricity Act in the manner that it considers is best calculated to implement, or to ensure compliance with, any binding decision of ACER or the Commission made under the Third Package. The IEM also allows national regulators to grant favourable treatment of new infrastructure and upgrades by way of exemption for a defined period from Third Package rules on third-party access, unbundling and tariffication. This option is open to energy infrastructure projects that enhance competition and security of supply, if it is assessed that they would not happen without the exemption due to the overall project risks (Electricity Regulation, Article 17).

NRAs work together under CEER, a not-for-profit association established in 2000 to facilitate the creation of the internal energy market. CEER focuses on informal activities to complement the formal mandate of ACER (see below).

Transmission System Operators (TSOs)

The Third Package both increased the independence of unbundled TSOs and required their increased cooperation at European level, mainly through ENTSO-E (see below). System reliability remains the responsibility of each network operator, but as noted in the IEA's 2014 *In Depth Review of EU Energy Policies*, Europe's combination of market integration and growing shares of VRE is starting to require closer cross-border co-ordination.

In the EU, TSO control zones coincide with national borders in the majority of cases (the exception being Germany). Consequently, TSOs are regulated to maximise available transmission capacity, in particular with regard to interconnectors. Another notable exception to the TSO control zone coinciding with national borders is TenneT, which operates both in the Netherlands and across the border in north-western Germany; however, TenneT's regulated activities are managed at a country level as two distinct operating segments, under the Netherlands' NRA Autoriteit Consument & Markt (ACM) and the German NRA Bundesnetzagentur (BNetzA).

European institutions

In relation to energy security, the Security of Electricity Supply Directive establishes measures aimed at safeguarding the security of electricity supply, to ensure the proper functioning of the internal market, an adequate level of interconnection between member states, an adequate level of generation capacity, and balance between supply and demand. Following concerns surrounding the delivery of Russian natural gas via Ukraine, the EU heads of government further asked the European Commission to draw up a comprehensive plan for the reduction of EU energy import dependence by June 2014. This Energy Security Strategy focuses on gas, but encompasses electricity, as well as nuclear, oil, and other areas (EC 2014b and EC 2014c).

European Commission

The Commission holds the right of initiative to propose laws for adoption by the EU institutions. The Commission makes proposals to meet its obligations under the Treaty, or because another EU institution, country or stakeholder has asked it to act. Before making proposals, the Commission consults widely among stakeholders and provides a prior assessment of the potential economic, social and environmental impact of a given piece of legislation. Principles of subsidiarity and proportionality apply, so that the EU may only legislate where action will be more effective at EU level than at national, regional or local level, and then no more than necessary to attain the agreed objectives. Once EU legislation has been adopted, the Commission ensures that it is correctly applied by the member states.

Several Commission departments have responsibilities regarding energy: the Directorate General (DG) for Energy; DG Competition; DG Internal Market; and DG Climate Action.

DG Energy drafts energy sector legislation and strategy, including the Energy Security Strategy, and prepares the annual internal energy market progress report and State of the Energy Union report (new as of November 2015). Member states – along with the European Commission, ENTSO-E, and others - identify PCIs (see “Transmission planning and development” below).

Since 2013, DG Energy has convened an Electricity Coordination Group made up of member state representatives, national regulators, ACER and ENTSO-E to advise on strategic issues in electricity policy. In March 2016 the Commission further set up a new Expert Group on Electricity Interconnection Targets made up of stakeholders (industry organisations, academic researchers, NGOs) to advise on the feasibility of the proposed 15% by 2030 interconnection target.

The Commission frequently uses external consultancy reports as a first step in scoping new areas for policy action. Recent examples are: *Options for future European Electricity System Operation*, December 2015, which recommends replacing national arrangements with the centralisation of TSO functions in long-term network planning and in system operation before real time timeframes; and *Review of Current National Rules and Practices Relating to Risk Preparedness in the Area of Security of Electricity Supply*, May 2016, a fact finding overview of the current legal framework and practices across the EU member states (EC, 2015a and EC, 2016c).

Consultation of the private sector and other stakeholders – typically national governments, academic experts, and NGOs – takes place both through public written consultation processes and both formal stakeholder meetings and informal meetings at the request of interest groups. Trade associations have been directly involved in the Gas Coordination Group but are not currently invited to participate in the Electricity Coordination Group.

Agency for the Cooperation of Energy Regulators (ACER)

The Third Package also created new institutions to deliver the IEM. These include ACER, based in Ljubljana in Slovenia, and the European Network of Transmission System Operators for Electricity (ENTSO-E, see next) based in Brussels.

ACER is an independent EU agency tasked with fostering cooperation among the NRAs in regard to EU legislated objectives. The electricity department works in four key areas:

- Preparation of Framework Guidelines and Network Codes.
- Electricity Regional Initiatives.
- Infrastructure and network development.
- Market monitoring.

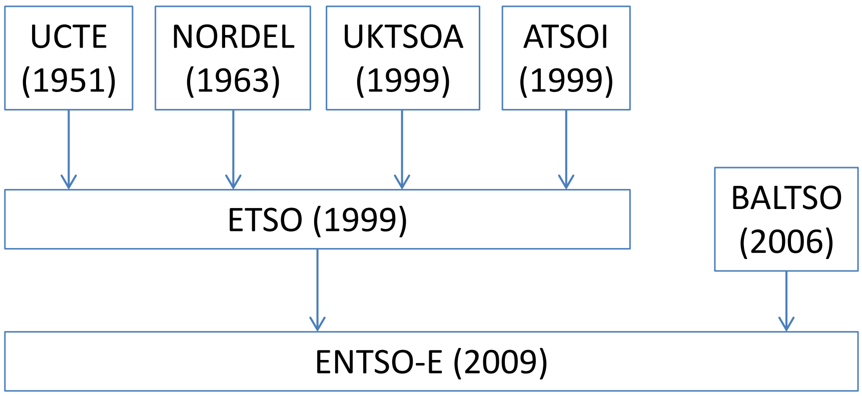
ACER is not a formal EU regulator, but rather a governance institution reliant on the authority of the NRAs. ACER can issue non-binding opinions and recommendations to the NRAs, TSOs and the EU institutions. It can also take binding decisions in specific cases on cross-border infrastructure matters where NRAs have not been able to reach their own agreement within six months, or upon a joint request of the NRAs. At the request of the Commission, ACER takes a leading role in the drafting of Framework Guidelines for Network Codes. ACER's annual work programme is a useful guide to its priorities and tasks (ACER, 2015a).

The limited role of ACER as a regulator for the EU stands in stark contrast to, for example, the Federal Energy Regulatory Commission (FERC) in the United States. ACER is essentially a regulator of last resort, stepping in only where NRAs are unable to reach decisions among themselves. ACER can only advise on matters related to market design. FERC, on the other hand, has clear authority in a number of areas, such as in the regulation of the design of wholesale markets.

European Network and Transmission System Operators for Electricity (ENTSO-E)

ENTSO-E was established by the Third Package and represents 42 electricity TSOs from 35 countries across Europe (the EU 28 member states and neighbouring countries). Its work spans legal mandates for drafting Network Codes, coordination and monitoring of Network Code implementation, development of long-term pan-European network plans, publication of summer and winter outlook reports for short-term electricity system adequacy overview, and preparation of industry policy position papers. A parallel organisation, ENTSO-G, has a similar role for natural gas networks.

Figure 1.3 • History of ENTSO-E



Notes: UCTE was a network of 29 TSOs from 24 countries across Europe; NORDEL was composed of TSOs from Denmark, Finland, Iceland, Norway and Sweden; UKTSOA was composed of the TSOs of the United Kingdom; ATSOI was composed EirGrid and System Operator Northern Ireland (SONI); BALTSO was composed of the TSOs of Estonia, Latvia and Lithuania.

Source: ENTSO-E

ENTSO-E's short-term adequacy outlook is compiled on the basis of national forecasts by TSOs, and does not consider capacity limitations between countries and/or regions. The long-term EU-wide Ten Year Network Development Plan (TYNDP) is discussed below.

ENTSO-E also encourages the creation of Regional Security Coordination (RSC) entities for data-sharing among TSOs. ENTSO-E states that operating the power grid in real-time remains the responsibility of TSOs, but TSOs will more and more perform this task by relying on the information and strategies provided by the RSCs. Services performed by RSCs include providing a regional model of real-time the power flows and information such as the quantity of wind or solar power produced in a region, or advanced calculations to tell TSOs which remedial actions are the most cost-efficient, without being constrained to national borders.

The forthcoming 2016-17 EU legislative agenda

While much progress has been made toward the completion of the IEM, it is clear that there is more work to be done. The First, Second and Third Packages, combined with the EU's Energy and Climate 2020 targets, have set a clear direction for Europe's energy market: continued liberalisation, integration, and decarbonisation.

Decarbonisation and, in particular, the need to improve power market design to better accommodate VRE is driving the EU's current legislative effort, currently referred to as the "Winter Package".

The Winter Package draft legislative proposals will not be finalised until the end of 2016, and therefore any description of what it may contain should be taken as speculation. However, some of the topics to be addressed can be described at a high level. In particular, the legislation will aim to tackle the continued divergence of national policies on capacity mechanisms (CMs) and renewables support schemes. It will also likely continue to advance market coupling.

The view of the IEA is that a lack of standardisation among intraday market designs remains a barrier to moving EU market coupling beyond the day-ahead period. For example, some markets require intraday participants to bid in 15 minute increments, while others require 20 minutes. Some markets offer continuous bidding, where all bids and offers are matched as they are submitted, while others only perform the bid-offer matching at the end of the intraday period. In order for intraday market coupling to thrive, products[14] and auction procedures must be harmonised. It is expected that the Winter Package will likely to address this challenge.

Another problem is an absence of coordination among countries on resource adequacy. In particular, some countries continue to develop nationally focused CMs while at the same time attempting to couple wholesale markets across borders. Yet, as noted above, CMs can impact wholesale markets. The lack of coordination means impacts will be less predictable, which may in turn undermine market coupling. The Winter Package will probably also address the need to better coordinate the development of such mechanisms. It is unclear, however, whether it will attempt to fully harmonise the design of CMs, or simply call for more cross-border consultation and coordination on their development and design (for example, by requiring that national CMs allow external resources to participate).

Related to the development of CMs, a further obstacle to their harmonisation across borders, is lack of consistency among countries on how to measure security of electricity supply. There is no single reliability standard across the EU, and this makes it difficult – though not impossible – to develop cross-border CMs. For example, differing reliability standards will lead to different reserve margin requirements and, therefore, differently sized mechanisms. This is not an absolute barrier, however, because, as experiences in the US have shown, it is possible to develop CMs that allow for differing regional reliability requirements by creating locational pricing driven by differing, administratively determined demand curves (IEA, 2016a). Certain aspects of CMs, however, nonetheless need to be harmonised, such as the capacity product definition or the performance requirements (and related penalties for non-performance).

The Winter Package is also expected to almost certainly attempt to address the increasing need for flexibility in the European power system. As the penetration of VRE increases, concerns over flexibility (or lack-thereof) increase as well. At a minimum the Commission is likely to address this through continued efforts to couple intraday markets and through the further development of cross-border balancing markets.

[14] Here and throughout the report, "product" refers to the required delivery period.

Finally, and critically from the perspective of electricity security, the Winter Package will likely try to improve European responses to emergency events. In particular, it may attempt to harmonise the various existing definitions of emergency situations, and to increase the level of coordination on emergency response preparations and actions.

System Security

Cross-border electricity trade

Network Transmission Capacity and security of supply

Calculating the available network capacity of a given European transmission system is the sole responsibility of the TSO in question. How that capacity is calculated is defined by national grid codes, which must be approved by the relevant NRA (and only that NRA). Similarly, TSOs also have the responsibility for calculating cross-border transmission capacity. By definition, however, cross-border interconnections involve two or more power systems – and therefore two or more TSOs. Historically, cross-border transmission capacity has been calculated either separately by the interconnected TSOs (leading to potential mismatches in estimated cross-border capacity), or in a harmonized fashion a bi- or multi-lateral basis (leading to the possibility of calculations that are harmonized at a regional level but that diverge across Europe). The Network Code on CACM requires, among other things, more formal collaboration and harmonisation of the way in which transmission capacity is calculated.

The transmission capacity calculation has multiple dimensions. The primary goal is to calculate the Net Transfer Capacity (NTC), or the capacity available for commercial transactions. All transmission capacity products offered by the system operator – annual, monthly and daily – reflect the available NTC for those periods. The amount of NTC available may vary depending on season, maintenance schedules, or the level of congestion in the system. (Agora Energiewende, 2015).

The NTC is usually calculated as the Total Transmission Capacity (TTC) minus the Transmission Reliability Margin (TRM). Divergent methodologies for calculating either TTC or TRM, therefore, can affect commercial operations.

The TTC is generally defined as the maximum transmission capacity available for the exchange of electricity without undermining the stability of either of the interconnected systems. Among other factors, the TTC calculation considers scheduled and unscheduled flows, the potential for loop or transit flows (see below) and N-1 criterion.[15] The tightly interconnected nature of the European grid and the fact that the grid is generally meshed (as opposed to a linear or radial grid) means that electricity flows within one TSO's system may be affected by flows outside that system. Therefore, every system operator performs simulations aimed at assessing electricity flows within the grid based on feasible possible scenarios. As the calculation day approaches, scenarios are increasingly well defined (based on, for example, bid and offer data and weather conditions) and the level of uncertainty decreases.

The TRM is determined by the system operator based on the minimum amount of interconnected capacity they require in order to maintain system security in a scarcity event. Put another way, it is the minimum amount of capacity a given system would need to meet demand in the event of an unexpected generator outage (Elia, 2016).

[15] N-1 refers to the ability of the power system to maintain security of supply even after the loss of one critical component (e.g. a transmission line or a large power plant)

Harmonised calculations of TTC and TRM among interconnected TSOs are crucial both for commercial operations and long-term resource adequacy. In a meshed network such as the one that exists in Europe, where TSOs are connected through multiple pathways and where many countries may act as an intermediary for power flows between two or more other countries, a lack of a common approach to these calculations may lead TSOs to make improper decisions in real-time based on assumptions that conflict with other TSOs, and will certainly lead to divergent views over regional resource adequacy.

Loop and transit flows

One driver for developing common NTC calculation methodologies is the problem of loop and transit flows. Loop and transit flows are unscheduled power flows (i.e. physical flows that differ from contracted power flows) that originate in a given jurisdiction but which cross through one or more neighbouring jurisdictions. The primary difference between loop and transit flows is where those flows terminate: loop flows terminate in the originating jurisdiction while transit flows terminate in a different jurisdiction. Loop flows are only possible in meshed networks, where each jurisdiction's grid has multiple exit and entry points.[16]

In Europe's restructured power systems, generation schedules are determined ahead of real-time through the matching of supply and demand bids in various power exchanges. Real-time power flows, though, are governed purely by the laws of physics. Unanticipated changes in the power system can therefore lead to physical power flows that differ from scheduled power flows.

Unscheduled power flows are a natural part of any power system, as both load and generation have a certain degree of inherent unpredictability. Within a system operator's jurisdiction, however, unscheduled power flows can be handled in the same way that all real-time operations are handled: though the management of system resources under the operator's direct control.

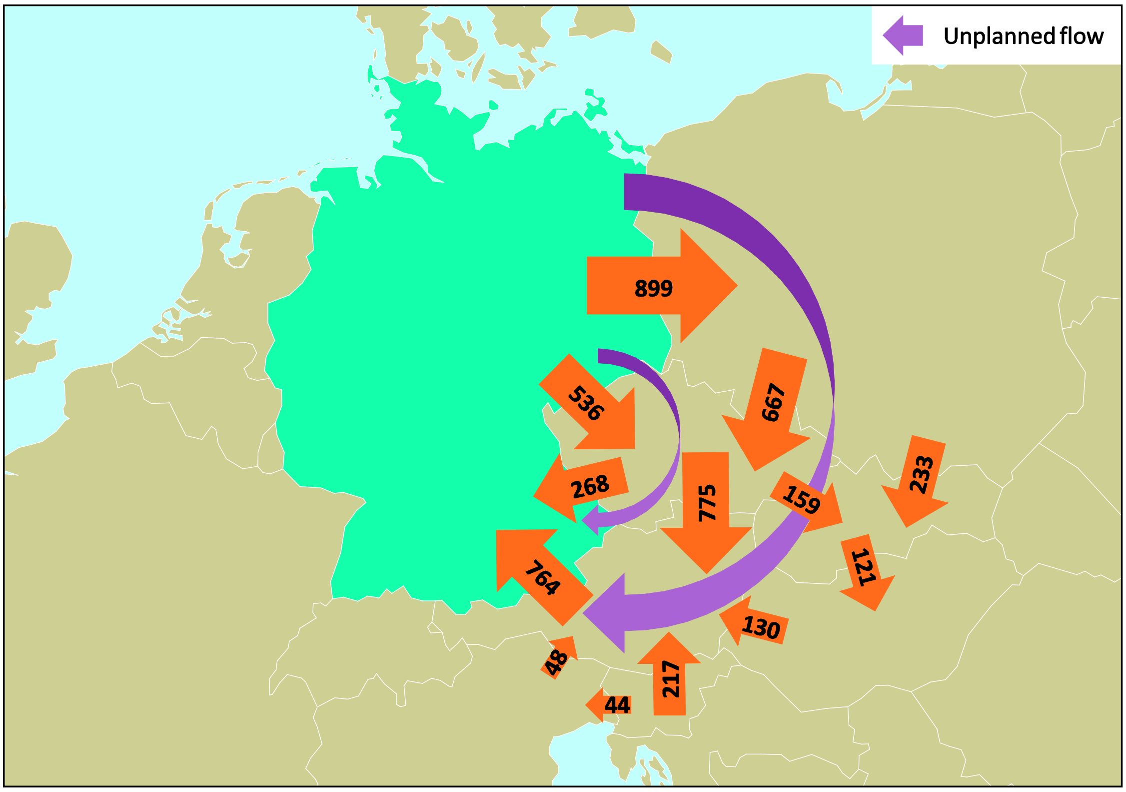
Loop flows, however, present a particular challenge, as they involve power flows that originate outside a system operator's area of control, but which the operator can only respond to using their own, local, resources. By definition, therefore, loop flows are a purely cross-border issue.

A primary cause of loop flows in Europe today is the relatively rapid increase in the penetration of VRE in certain jurisdictions. Internal network infrastructure development has not always been able to keep pace with generation deployment, and so power flows are diverted across borders. A lack of multi-jurisdictional transmission planning means there is no easy way to reduce or remove loop flows by coordinating cross-border or internal transmission network developments.

The example most often cited is that of Germany, and the loop flows created by excess wind generation. Most of Germany's wind farms are located in the north of the country, while the largest load centres tend to be in the south. Limited internal network capacity within Germany, however, prevents power from flowing from north to south. As a result, power instead often flows across the border to Poland, where it may then be re-exported south to the Czech Republic, and then back into Germany (Figure 1.4).

[16] For simplicity, this section will focus its discussion on loop flows, which tend to be the more discussed of the two phenomena. In practice, the issues and potential responses are similar.

Figure 1.4 • Loop flows between Central and Eastern Europe (MW, January 2011 to December 2012)



Source: Joint study by ČEPS, MAVIR, PSE and SEPS regarding the issue of unplanned flows in the Central Eastern European (CEE) region in relation to the common market area Germany – Austria (January 2013)

The cross-border nature of loop flows means they can only be resolved at a regional level. In a European context there are three relevant jurisdictions: the originating jurisdiction, the transit jurisdiction(s), and the EU. The incentives for whether and how to manage loop flows, however, differ among the relevant parties, creating a fundamental source of tension.

Take, for example, the perspective of the originating jurisdiction. The originator has a number of possible ways to manage over-generation, including curtailment of local generation and increasing internal network capacity. Both of these solutions, however, impose a cost on the system – a cost which is born by some combination of local generators and local ratepayers, while the benefits accrue mainly to ratepayers outside the TSOs control area. The lack of joint transmission planning means TSOs are often unable to justify investments in transmission lines which would reduce loop flows but not reduce costs to local consumers.

Another option, relevant to markets with zonal pricing, is to redefine the zone boundaries to better represent internal constraints. Doing so would allow market prices to more accurately reflect the presence of loop flows, but does nothing to eliminate the flows themselves (Thema Consulting Group, 2015).

If the originator does not take action, the transit jurisdiction is forced to respond. The most common response is re-dispatch – that is, curtailing local generation to reduce network constraints and allow for the flow of the unscheduled imported generation. An alternative is to follow the example of Poland and the Czech Republic, which (along with other countries in Europe) have responded by installing phase shifters. These allow the respective TSOs to dynamically restrict flows over a given interconnector. In either case, the cost of dealing with loop flows is born in part or in full by the transit jurisdiction.

From the perspective of the EU the primary concern is that the presence of loop flows undermines the development of the IEM. This is in part because loop flows reduce the ability or willingness of TSOs to rely on power flows from neighbouring jurisdictions, in particular during times of scarcity. This manifests most directly in a reduction on a forward, day-ahead, and real-time basis of interconnector NTC. The absence of a common, or at least harmonized, set of rules for determining NTC has led TSOs to take a generally conservative approach to how it is calculated.

An excessively conservative approach to calculating NTC will, as a consequence, require more generating capacity to be available within a given jurisdiction. From a resource adequacy perspective, therefore, limiting NTC can exacerbate the problem of excess capacity and, by extension, impact the wholesale market. However, this is primarily an economic impact, and not one that necessarily undermines real-time system security.

Given the EU's lack of jurisdictional authority on dispatch decisions, it is limited in the ways it can respond to the issue of loop flows. Resolving the coordination issues around calculating NTC is one area where the EU can have a concrete impact. The EU has also employed the CACM Network Code as a tool to tackle loop flow issues. The CACM is intended to lay out a minimum set of harmonised rules for market coupling. In practice this means creating common methodologies to match bids and offers and calculate interconnector capacity, and to coordinate re-dispatch when it has cross-border impacts (EC, 2015b).

The ultimate goal is to develop a single methodology for all TSOs in Europe (plus relevant TSOs in non-member countries, e.g. Switzerland), but in practice this is being implemented first at a sub-regional level among distinct groups of countries.

TSOs from the Czech Republic, Hungary, Poland and Slovakia (each of which are impacted to differing degrees by loop and transit flows that originate in Germany) have advocated for the full implementation of CACM as a way of addressing the issue of loop and transit flows (ČEPS et al., 2013). They have also noted, however, that it is important which institutions implement the CACM. They further advocate for splitting Germany and Austria's common price zone into two zones, as well as the explicit inclusion of Germany and Austria in their own implementation. The German regulator, on the other hand, has argued that any benefits that accrue from splitting the market would be outweighed by the negative impacts of reduced market liquidity and competition (Frontier Economics, 2011). This illustrates the challenge of implementing CACM or similar solutions in a piecemeal fashion, as *a priori* there is no easy way to decide which jurisdictions should be included in which sub-regional implementation effort.

When fully implemented, CACM will likely reduce the negative impact of loop flows on system security. However, it cannot fully eliminate the problem, as it does not resolve the issue of internal network constraints or over-generation from sources such as wind, and it does not in any way change the jurisdictional boundaries. Combining neighbouring jurisdictions into a single control area would, in contrast, by definition resolve the issue of loop flows, but the presence of loop flows is not sufficiently disruptive to system operations to warrant such a step on its own.

Resolving the loop flow issue remains important to the overall objective of enhancing EU electricity. Reducing the prevalence or impact of loop flows should help to improve system security by making it easier for TSOs to rely on their neighbours during times of system stress or scarcity.

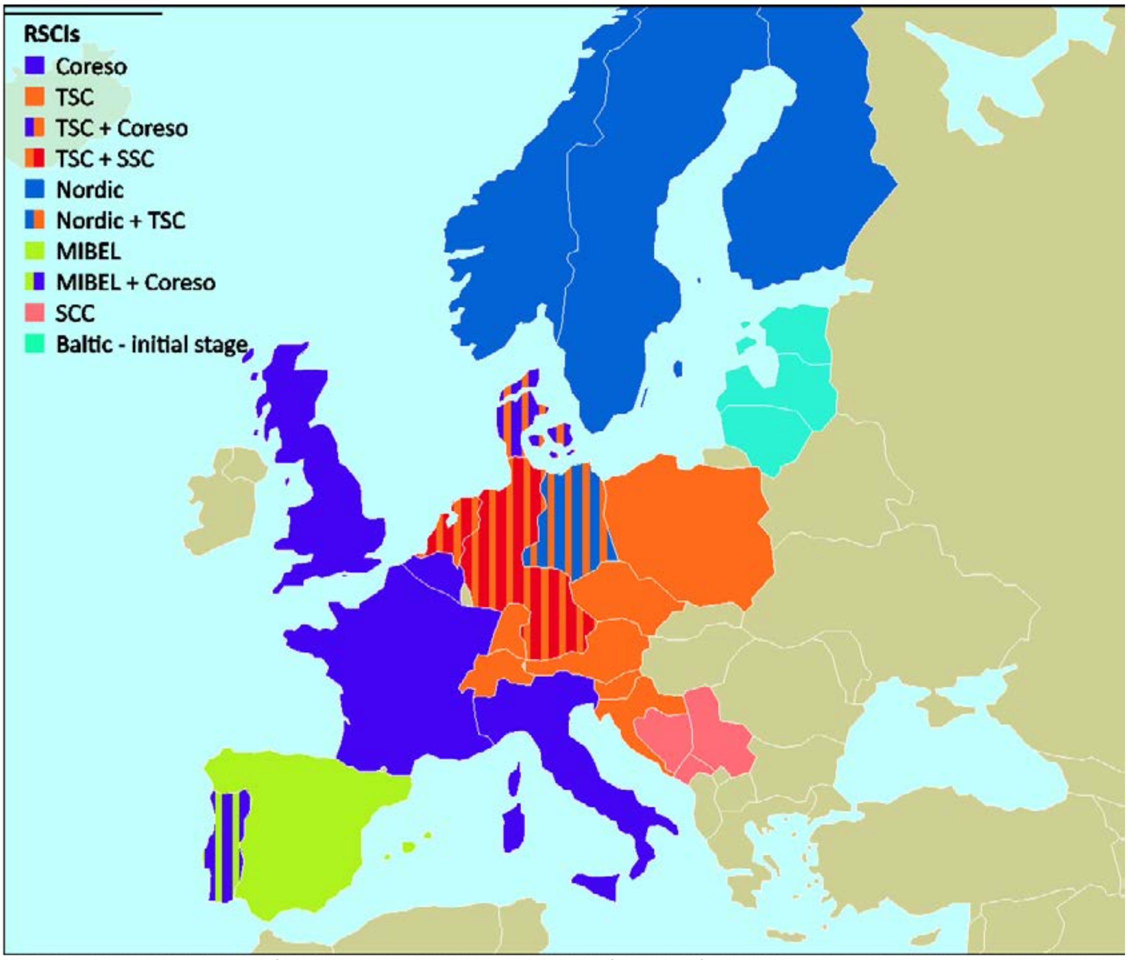
Regional Security Cooperation Initiatives and the proposed Regional Operating Centres

Responsibility for maintaining system security ultimately lies with the TSOs. This will remain true even if the EU fully completes the IEM. However, each TSO only has direct oversight of its own control area and, in Europe, most of these control areas are delimited by national boundaries.

The interconnected nature of the European power system means that TSOs need to cooperate on at least a regional basis in order to maintain security of supply. Recognizing this fact, starting in 2008 TSOs began to develop Regional Security Cooperation Initiatives (RSCIs), also known as Regional Security Coordinators (RSCs). The first RSCIs were set up on a voluntary basis by TSOs from 2008, with Coreso (based in Brussels) and TSC (Munich) as pioneers. In 2015, the SCC RSCI was also created in South East Europe (SEE), based in Belgrade. In December 2015, a Multilateral Agreement on Regional Operational Security Coordination was signed by 36 interconnected TSOs and ENTSO-E to roll out the RSCI across continental Europe (Figure 1.5). The role of RSCIs is formalised under the draft Network Code on System Operation, and in May 2016, the Nordic TSOs started discussions aiming to create a Nordic RSC by the end of 2017.

RSCIs are owned by their member TSOs, and are primarily meant to help manage congestion on a regional level. For example: Coreso serves TSOs in Belgium, Italy, France, Portugal, the UK, and part of Germany; TSCNET serves Austria, the Czech Republic, Slovenia, Denmark, Croatia, Germany, Hungary, the Netherlands, Poland, and Switzerland; and SCC covers Southeast Europe (including some non-EU members, such as Turkey). Notably, there are overlaps, with some TSOs participating in multiple RSCIs (for example, 50 Hz in Germany, which is a member of both Coreso and TSCNET).

Figure 1.5 • RSCIs in Europe



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area

Source: ENTSO-E

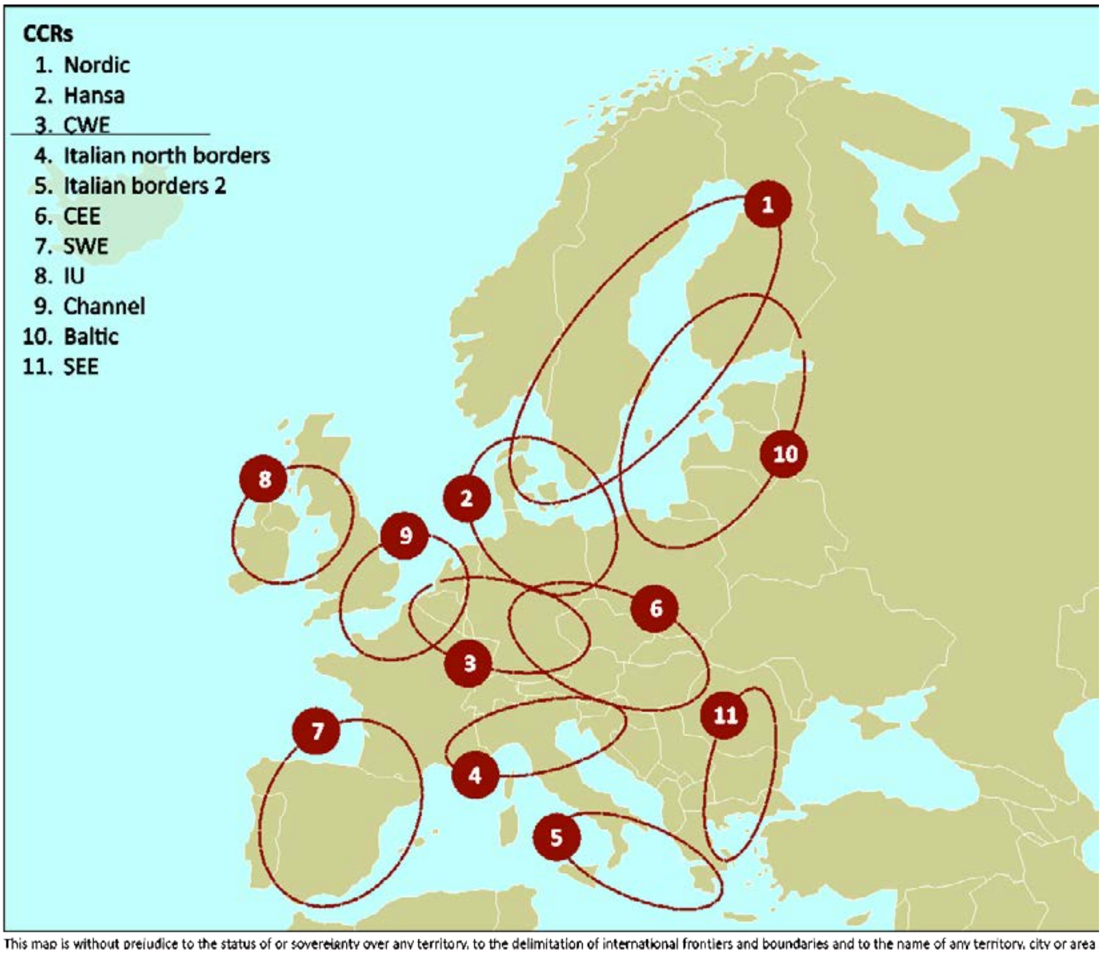
RSCIs do not operate in real time. Instead, using data provided by each member TSO, the RSCIs develop detailed regional forecasts of system conditions, and provide these to the TSOs they serve, along with specific recommendations for how to coordinate responses (EC, 2015a).

The Electricity Regulation in the Third Package requires TSOs to deepen cooperation on regional system security. Among other things, it mandates enhanced regional cooperation on security and system operations. In 2015, the TSOs (plus ENTSO-E) signed the Multilateral Agreement on Participation, which requires all ENTSO-E members to join an RSCI. It has also been proposed that the responsibility of the RSCIs be expanded.

One proposal is for RSCIs to take on more of an operational role. RSCIs may therefore evolve into Regional Operational Centres (ROCs; these are sometimes also referred to as Regional System Coordination Service Providers, or RSCSPs). The development of ROCs is a key component the IEM, and so they are mentioned explicitly in the grid code on System Operation Guidelines. Each ROC would serve a single Capacity Calculating Region (CCR), as defined by ENTSO-E (Figure 1.6), though the geographic scope of these regions may change. In addition, efforts by the ROCs are meant to be harmonised across each synchronous area.

The ROCs, if created, would provide at least five primary services: common grid modelling; analysis of system security; coordination of outage planning; short- and medium-term resource adequacy forecasts; and coordinated calculation of transmission capacity (ENTSO-E, 2016a).

Figure 1.6 • ENTSO-E defined CCRs



Source: ENTSO-E (https://consultations.entsoe.eu/system-operations/capacity-calculation-regions)

While these new ROCs would take on an expanded role, there are limits to how far they can extend before coming into conflict with the TSO system as it is currently structured. Because each TSO is responsible for its own control area, certain tasks must remain at the national (or sub-national) level. In particular, many tasks that occur in real-time (after gate closure) are difficult or impossible to centralize, as they cannot be separated from local system operations without undermining system security. For example, manual interventions to maintain voltage levels cannot be done without a finely detailed understanding of the particular power system. Regionalisation of these functions would, in essence, require replacing individual (national) TSOs with a single regional TSO.

By building on the success of the RSCIs, ROCs would continue a bottom-up approach to the development of regional institutions. They are therefore less likely to undermine the system security of the TSOs they serve. However, this may also act as an obstacle to any efforts to further integrate system operations across borders.

ROCs do not function as regional TSOs, and so tasks that are critical to maintaining security of supply will remain national. This points to an inherent tension in the effort to create the IEM: so long as TSO operations remain separate, the IEM will remain limited in its potential scope. And yet efforts to regionalise system operations are crucial to the long-term success of the IEM. This suggests that there will need to be more collaboration across borders in the future (IEA 2014a; IEA, 2014b).

Resource Adequacy

Transmission planning and development

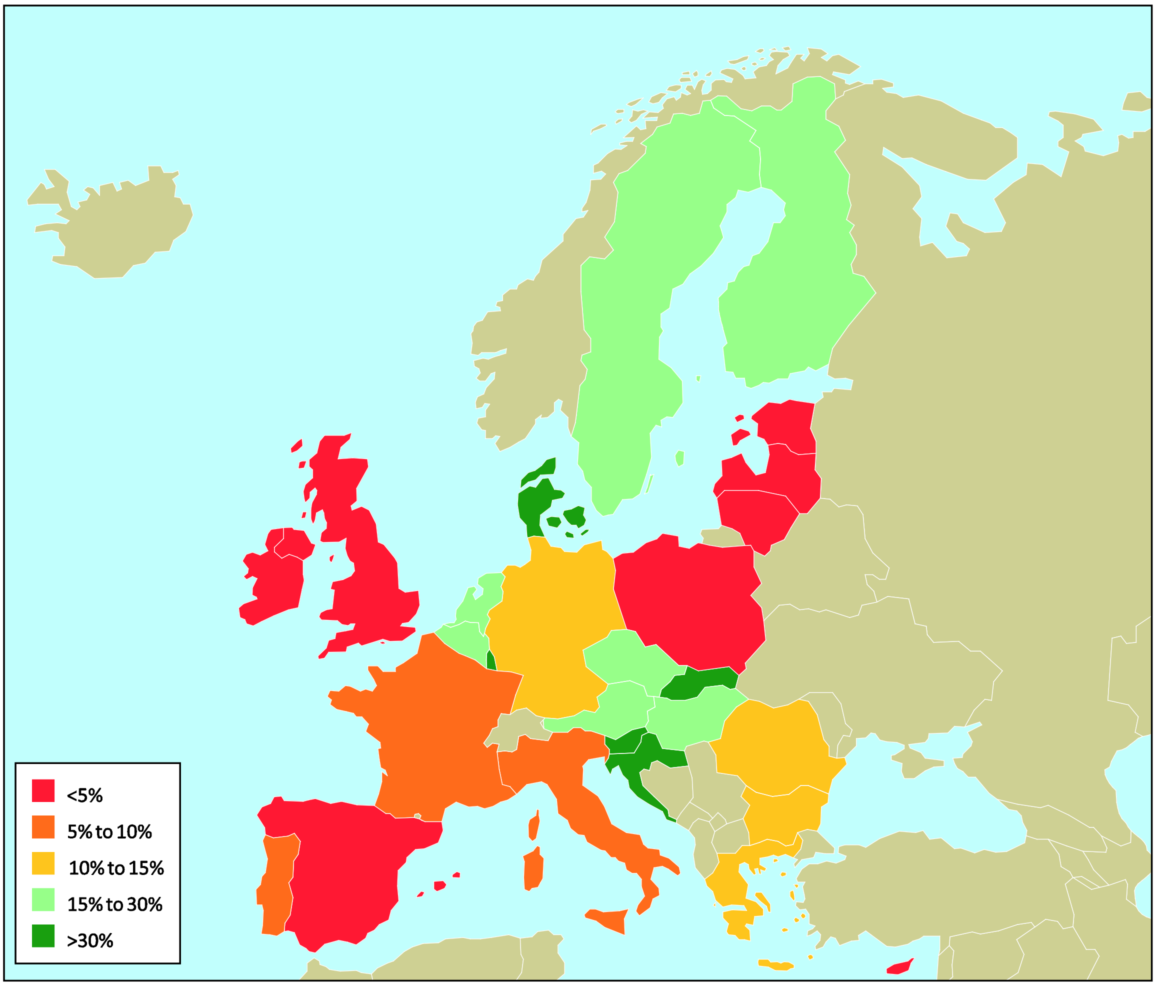
Interconnectors amount to 11% of installed generation capacity across European countries, on average, although there is significant regional variation. For example, while Switzerland's level of interconnection is equivalent to 48% of its internal generation capacity, Spain's interconnections with France are equivalent to only 3% of domestic generation. The economic benefit to the EU of increasing the level of interconnections are widely recognized, and this is one of the key pillars of IEM project. According to one estimate, increasing interconnections across the continent could save European consumers between EUR 12 billion and EUR 40 billion annually by 2030 (Booz & Co, 2013).

As outlined above, in 2015, the EU set a goal of increasing interconnection to 15%. This decision reflected the political priorities of some member states, and was accompanied by a caveat requiring cost-benefit assessment, as it is not clear that the 15% level will be appropriate for the EU as a whole. The Commission therefore intends to report in 2016 on progress towards the completion of a list of the most vital energy infrastructures and on the necessary measures to reach the interconnection target. The criteria for this list will need to take into account not only investment costs, but also public acceptability. Public opposition to the development of new, above-ground transmission lines is significant in some parts of Europe. A thorough cost-benefit analysis could offer a concrete reason for constituents to support a particular project.

In Europe, the cost allocation of cross-border transmission lines is done under terms defined by mutual agreements between the relevant countries. In general, the cost of interconnectors built under bilateral agreement has been split on a 50-50 basis. This is not necessarily restricted to transmission lines that cross a border, but can also include lines developed within one country that heavily influences the networks of neighbouring countries. It is the responsibility of the relevant NRAs to collectively determine the appropriate cost apportionment. Under the Third Package, however, ACER can decide on cost allocation if NRAs cannot come to an agreement. This right is limited to cases where all of the countries in question are EU members (see Box 1.4).

In other parts of the world, for example the United States, merchant investors have begun to play a larger role in developing transmission lines, including lines that cross jurisdictional boundaries, although the sums are still small in absolute terms. Merchant investments are privately funded and so do not impact the rate base, with investors recovering their costs by taking advantage of inter-regional price differences, i.e. congestion rents, or by selling right of access to third parties. This model is in particular well suited for DC lines linking separate networks (IEA, 2016b). The merchant model has been less successful in Europe, however, in part because existing regulations tend to favour regulated investments. Merchant lines have mainly been discussed in the context of sub-marine HVDC cables and in the so-called "e-Highway 2050", a proposal to overlay the European grid with a network of long-distance HVDC cables.

Figure 1.7 • EU interconnection levels in 2020 assuming completion of current PCIs



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: IEA, 2015

The EU has taken some steps to encourage more merchant investments, in particular through Regulation 1228/2003/EC, which allows projects to be exempted from third-party access requirements under a limited set of circumstances. In particular, a project may be declared exempt if it meets the following criteria:

- The investment must improve competition in the interconnected markets.
- Projects must be of sufficiently high risk that they would not be allowed as regulated assets.
- The line in question cannot be owned by a TSO or a company legally connected to a TSO.
- Users of the interconnector must pay the relevant charges.
- No costs, in part or in total, can be passed on to consumers through the rate base of the interconnected T&D systems.
- The exemption must not undermine the operation or functioning of any associated regulated assets.

Each exemption must be granted on a case-by-case basis, and in practice exemptions have only been granted to five projects (Oxford Energy, 2016). Merchant line development in the EU has in particular been hampered by a lack of consensus on who should pay for any required network reinforcements in adjacent networks.

Projects of Common Interest (PCIs)

The EU's primary tool for meeting the interconnection target is the Trans-European Networks (TENs) strategy providing for the selection of Projects of Common Interest (PCIs).[17] The Commission has emphasized that obstacles and delays to infrastructure permitting are a major factor holding back interconnection. Once selected, PCIs benefit from accelerated licensing procedures, improved regulatory conditions, and some access to financial assistance from the Connecting Europe Facility. In 2013, Europe adopted EU-wide guidelines for the establishment of PCIs as part of the Energy Infrastructure Package (Regulation 347/2013/EU). PCIs are selected by the European Commission on the basis of ENTSO-E's Ten Year Network Development Plan (TYNDP, see below).

A first list of PCIs published in 2013, based on TYNDP 2012, included 45 interconnection projects out of a total 134 electricity infrastructure projects. Slightly less than half of the interconnection projects are proceeding on schedule, while almost 30% are delayed (Figure 1.8). Key electricity projects include the Lithuanian-Polish power interconnection (LitPol) completed early in 2016, and the Bescanó-Santa Llogaiaat internal link near the Spanish-French border.

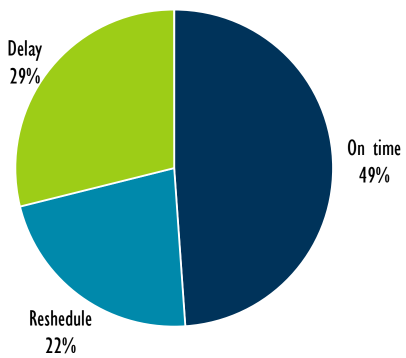
Regulation 1316/2013/EU establishing the Connecting Europe Facility foresees that the costs for the development, construction, operation and maintenance of a PCI should in general be fully borne by the users of the infrastructure. A PCI "should be eligible for cross-border cost allocation when an assessment of market demand or of the expected effects on the tariffs has indicated that costs cannot be expected to be recovered by the tariffs paid by the infrastructure users."

PCI guidelines require procedures for granting permits to be reduced to around 3.5 years through the creation of a one-stop-shop at national level for all permitting, while also requiring in depth public consultation on new infrastructure projects.

[17] In addition to transmission, PCIs may be electricity storage, power substations, and phase-shifters. The effort to synchronise the Baltic system to the rest of the EU is also classified as a PCI.

PCIs are selected based on a cost-benefit assessment of cross-border impact and positive net benefit for Europe. NRAs then have six months to agree on how to allocate the investment costs between the member states they represent. If they do not reach agreement, ACER takes a decision. ACER has also published recommendations on cost-benefit assessments based on NRA best practises. To date, ACER has intervened in two cases out of a total of 16 cross-border PCIs: a gas interconnection between Poland and Lithuania (GIPL) and the LitPol electricity interconnection. For LitPol, which has an estimated cost of EUR 416 million (LitPol Link, 2016), ACER determined that, while the benefits extended across multiple countries, the Lithuanian TSO is the net beneficiary and should therefore bear all investment costs. There is also one example of NRAs reaching bilateral agreement on a cost sharing agreement for a cross-border electricity interconnection between Latvia and Estonia. In this case, 90.1% of the cost was allocated to the Latvian TSO, while 9.9% was allocated to the Estonian TSO.

Figure 1.8 • The status of the interconnection projects in the first list of projects of common interest (PCI) as of May 2015

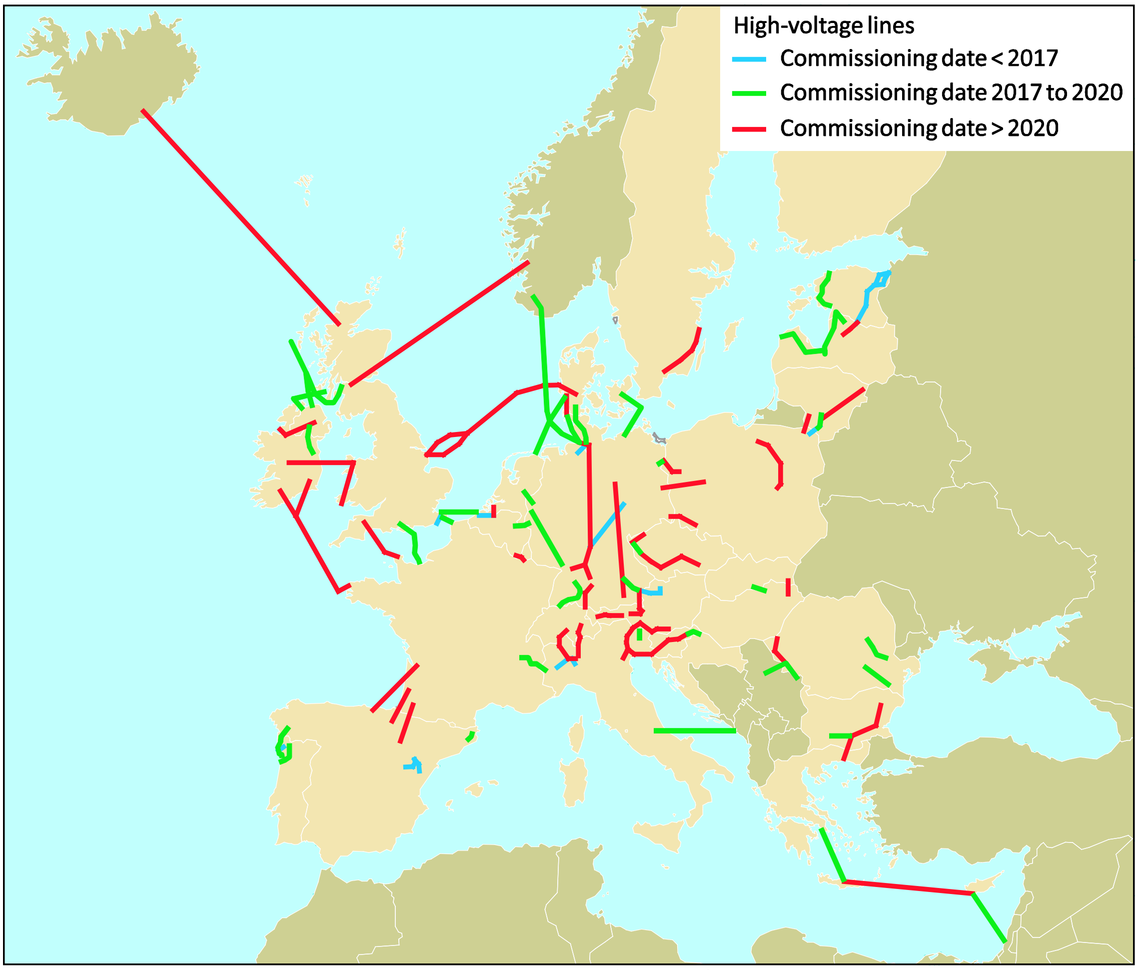


Source: Based on ACER 2015c

The list of PCIs is updated every two years to integrate new projects and remove any which have become obsolete meanwhile. The second PCI list was published in November 2015, based on TYNDP 2014, and has 195 projects: 108 electricity transmission, 77 gas transmission, seven oil pipelines, and three smart grid projects.

The 2014-15 selection process for electricity gave priority to projects that will contribute to the EU's 10% by 2020 interconnection target. This results in a large number of UK interconnection proposals, due to the UK's significant domestic capacity and, at present, limited interconnections to continental Europe. The list also highlights 27 projects as 'electricity highways' which can be expected to accommodate substantial inter-regional transfers of renewable energy over long distances.

Figure 1.9 • Transmission PCIs as of July 2016



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: EU (http://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/)

Ten-year Network Development Plans (TYNDPs)

While TSOs remain responsible for the development of their own transmission plans, in recognition of the importance of regional transmission planning, since 2010, ENTSO-E has published a Europe-wide TYNDP on a biannual basis. This co-ordinated planning initiative aims to cover the entire ENTSO-E region, and complies with the Third Package by providing an overview of the transmission expansion plans identified as necessary to facilitate EU IEM and other energy policy goals.

Each TYNDP is prepared starting with a set of future scenarios for the development and needs of the European power system. For TYNDP 2016, this time horizon is 2030. ENTSO-E considers regional studies as well as pan-European analyses to assess grid reinforcement projects. In parallel, it receives feedback from various stakeholders through consultations, public workshops and regular meeting of the Network Development Stakeholder Group (NDSG).

A TYNDP provides a feasible vision rather than a blueprint which can be expected to be fully implemented. TYNDP 2016, if developed, would fulfil the 10% by 2020 interconnection target, with the notable exception of Spain, which would achieve between 6% and 9%, depending on the scenario. The TYNDP 2016 grid reinforcements are developed on the basis of an EU-wide 2030 target of 27% of renewable energy in final energy consumption, translating as around 50% renewable energy in the electricity mix. Both enabling new connections and reducing congestion in the network are considered. The 27% renewables in final energy consumption target was adopted by EU political leaders in October 2014 and will be implemented through a forthcoming review of EU renewables legislation as part of the EU 2030 Climate and Energy Package, which forms the basis of the EU's commitments under the United Nations Paris Agreement on climate change.

TYNDP 2016 analysed five different 2030 scenarios (or "Visions"). Visions 1 and 3 build on national energy plans with a minimal harmonisation at European level. Visions 2 and 4 assume a stronger top-down European coordination, based on new optimisation methods. These four scenarios refocused on the Energy Union 2030 goals. Additionally, a new 2020 "Expected Progress" scenario was introduced as an intermediate step to any of the 2030 Visions.

The scenarios reflect increasing shares of renewable energy, also demand response (5% to 20% of peak load), and growth in electric vehicles and heat pumps (negligible to 10% of peak load).

The TYNDP exercise pinpoints ten main boundary-related interconnection challenges which are barriers to the development of power exchanges in Europe. Interconnection capacity between the Nordic/Baltic States and the Continental Europe East should be between 1GW to 2.5GW; between the United Kingdom, continental Europe and the Nordic countries, the present capacity of 3 GW should increase to 10 GW (ENTSO-E, 2015).

National policies and impact on generation diversity

In 2008, the EU adopted its first major Climate and Energy Package to deliver targets for 2020 to: 1) reduce greenhouse gas emissions by 20% compared to 1990 levels; 2) increase to 20% the amount of renewable energy in final energy consumption; and 3) improve the EU's energy efficiency by 20%. In 2014 the EU member countries adopted a more ambitious 2030 target: 1) a 40% reduction in emissions; 2) at least a 27% share of renewable energy in final energy consumption; and 3) at least a 27% reduction in energy consumption (compared to business as usual).

In order to achieve the 2020 renewables target, EU member states agreed to country-specific targets, some of which are quite ambitious (Table 1.1). To meet these targets countries have introduced a variety of direct financial support, and in some cases have granted renewable generators priority grid-access and dispatching.

For the most part, the cost of support schemes has been in line with expectations. A notable exception has been solar PV, which has seen deployment levels far above the levels expected, especially in the Germany, Italy and Spain (IEA, 2014c).

Table 1.1 • Share of renewable energies in gross final energy consumption in 2005, 2010, and 2014, along with the 2020 targets

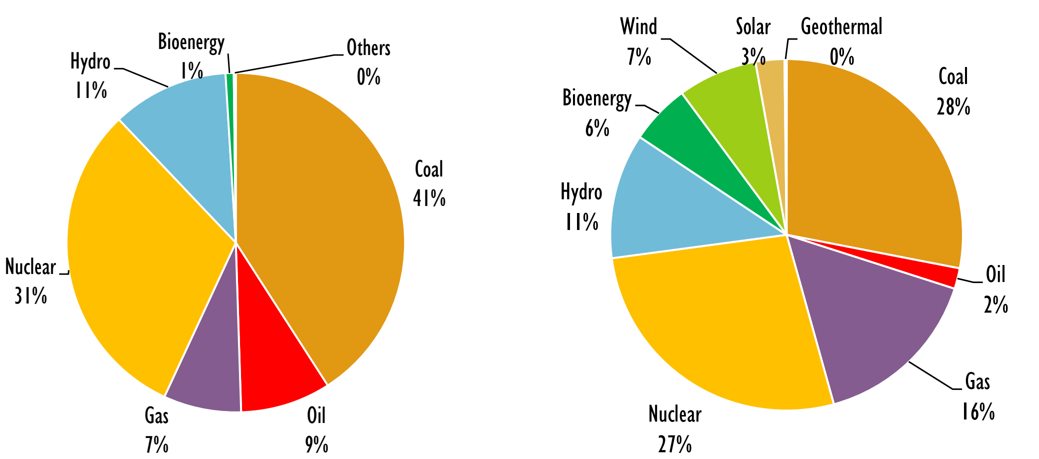
	2005	2010	2014	2020 Target
Austria	23.8	30.6	33.1	34
Belgium	2.3	5.5	8.0	13
Bulgaria	9.4	14.1	18.0	16
Croatia	23.8	25.1	27.9	20
Cyprus	3.1	6.0	9.0	13
Czech Republic	6.0	9.5	13.4	13
Denmark	16.0	22.1	29.2	30
Estonia	17.5	24.6	26.5	25

Finland	28.8	32.4	38.7	38
France	9.6	12.6	14.3	23
Germany	6.7	10.5	13.8	18
Greece	7.0	9.8	15.3	18
Hungary	4.5	8.6	9.5	13
Ireland	2.9	5.6	8.6	16
Italy	7.5	13.0	17.1	17
Latvia	32.3	30.4	38.7	40
Lithuania	17.0	19.8	23.9	23
Luxembourg	1.4	2.9	4.5	11
Malta	0.2	1.1	4.7	10
Netherlands	2.5	3.9	5.5	14
Poland	6.9	9.2	11.4	15
Portugal	19.5	24.2	27.0	31
Romania	17.6	23.4	24.9	24
Slovakia	6.4	9.1	11.6	14
Slovenia	16.0	20.5	21.9	25
Spain	8.4	13.8	16.2	20
Sweden	40.6	47.2	52.6	49
United Kingdom	1.4	3.7	7.0	15
EU (28 countries)	**9.0**	**12.8**	**16.0**	**20**

Source: http://ec.europa.eu/eurostat/tgm/table.do?tab=table&init=1&language=en&pcode=t2020_31&plugin=1

The impact of renewables growth on the European power system has been significant. From 2008 to 2013, for example, the share of solar PV generation increased from close to zero to 3% (Figure 1.10). Over that same period, wind power increased from zero to 7%, while coal's share of generation decreased from 41% to 28%.

Figure 1.10 • Generation mix in EU, year 2008 vs. year 2013



Source: IEA WEO (2010, 2015)

Meanwhile, across the EU, electricity demand growth has flattened to 0% per annum on average from 2007 to 2014, a significant drop from the 2.7% per annum increases that Europe had experienced since the 1970s. At the same time that demand has stagnated, investors have added 130 GW of renewable capacity and 78 GW of conventional generation. Only 44 GW of conventional generation has retired in the same period (WEF, 2015). Where priority dispatch is given to VRE generators, in effect, these generators have no incentive to respond to price signals. System operators must therefore take VRE generation as given, and use other resources at their disposal to balance them appropriately.

The combination of large quantities of low marginal cost VRE generation and its must-run status has been part of the reason some EU countries continue to experience low and at times negative wholesale prices. In addition, the expansion of VRE has increased regional imbalances, raising concerns about future congestion management.

As each country has ultimate authority over its own generation mix, phase out policies for coal and related policies for nuclear (see below) are likely to remain un-coordinated.[18] The impact of these policies, however, is relevant for the EU as a whole. There is therefore an opportunity, if not a requirement, for the EU to help support these policies. For example, EU-wide regional adequacy assessments can help identify which coal plants, if retired, would have cross-border security implications and could allow for the possibility of coordinating the timing of phase-outs across multiple jurisdictions.

Nuclear phase-out in Germany and Belgium

Germany's *Energiewende* (energy transition) policy commits Europe's largest economy to replacing its fossil fuel-based generation fleet with one that is nearly carbon-free well before mid-century, while at the same time phasing out nuclear power generation by 2022.

In September 2015 nuclear capacity in Germany was 10.8 GW, amounting to 5.7% of Germany's total installed capacity of 190.4 GW. The nuclear share in the electricity generation mix, however, was much higher, at 14% out of 543 TWh total generation in 2015. Germany's peak load is now less than half its total generating capacity, at 82.8 GW in 2013 and 84 GW in 2014 (Bundesnetzagentur, 2015). This overcapacity has meant that reducing nuclear capacity has not threatened security of supply. In the near-term, however, *Energiewende* has resulted in increasing power emissions due to lignite-fired generation which benefits from low fuel costs and a low EU ETS carbon price. Germany has also seen recent investments in new lignite capacity – in opposition to overall *Energiewende* goals.

Germany is also encountering issues of location mismatch between the retiring nuclear plants and new wind power capacity. The nuclear plants are mostly located in the south, near load centres, while most of Germany's wind farms are located in the north. Consequently, if grid development does not keep pace, in the medium term, Germany may come to depend more on fossil generation to supply load centres in the south or need to increase imports (for example, from France), while wind power output is exported to other markets.

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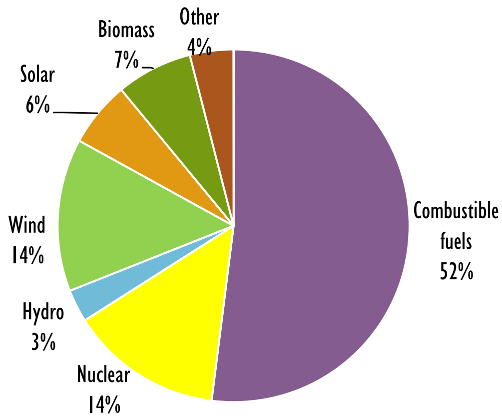
[18] Coal phase-out policies also have implications for the EU-wide carbon target. The wide-spread support of VRE across Europe has already impacted the ETS by increasing the penetration of renewables (and, by extension, decreasing the carbon intensity of the EU power system) faster than the markets would have supported if driven by the ETS price alone. This has led to a relative overabundance of ETS allowances and a depressed ETS price. A phase out of coal generation would naturally also reduce the emissions intensity of the power system. If the ETS allowances are not adjusted to reflect this fact, the ETS price will remain depressed even longer than is currently expected. Coordinating adjustments to the ETS with coal phase out schedules would require explicitly connecting the two, so that allowances are removed from the ETS in proportion to the carbon emissions avoided by the early retirement of a given coal plant.

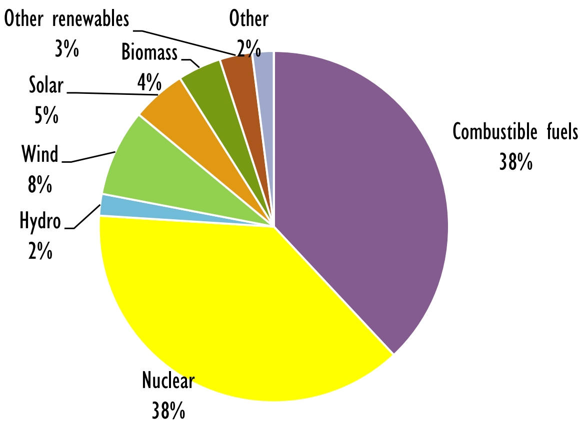
Figure 1.11 • Germany's electricity generation mix (2013)



Source: ENTSO-E, https://www.entsoe.eu/db-query/production/monthly-production-for-a-specific-country

In Belgium, nuclear in 2015 amounted to 30% of total capacity (6 GW out of 20.6 GW) and provided 38% of generation (De Clercq, 2015). According to the current phase-out plan its nuclear power plants will be shut down between 2022 and 2025. Post-2025, there are concerns that Belgium might be unable to meet domestic demand with domestic generation, resulting in increased import dependence (for more, see Case Study 2, Box 2.1).

Figure 1.12 • Belgium's electricity generation mix



Source: ENTSO-E, https://www.entsoe.eu/db-query/production/monthly-production-for-a-specific-country

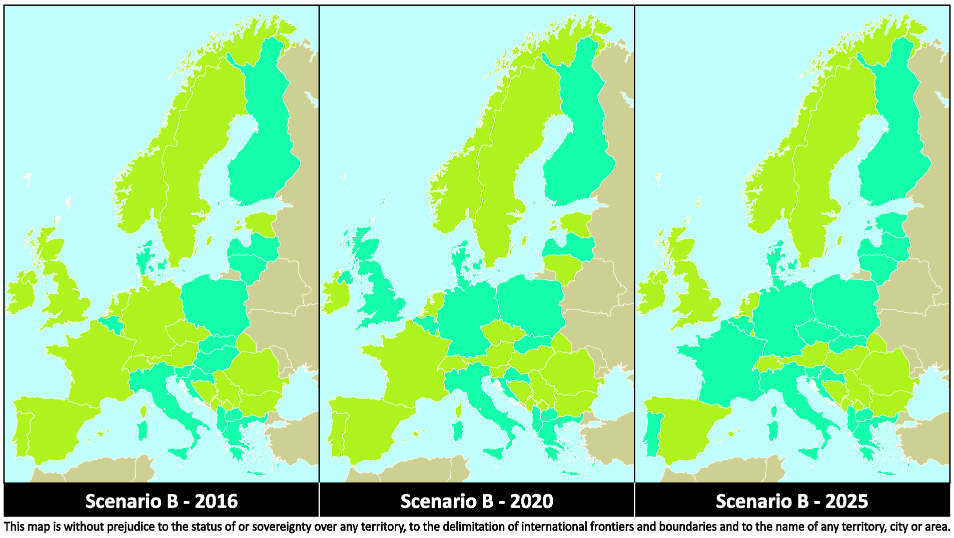
ENTSO-E's scenario outlook and adequacy forecast

As briefly outlined above, the Third Package also requires ENTSO-E to publish a ten-year resource adequacy assessment, the Scenario Outlook and Adequacy Forecast (SO&AF). This was initially intended to be a biannual exercise, but since 2011 ENTSO-has considered it important to publish the SO&AF on a nearly annual basis.

The SO&AF 2015 contained two important improvements over previous versions. First, it measured adequacy on a monthly basis over the ten year forecast (period 2016-2025). Second, it included for the first time a "simultaneous ENTSO-E regional assessment to the feasibility of improving the (national) level of adequacy by means of imports from a Pan-EU point of view" (ENTSO-E, 2015). This was therefore the first in which the contribution of capacity to cross-border resource adequacy was considered.

The SO&AF finds that, with assumed load growth,[19] there will be sufficient resources available to meet demand needs to 2025 under the crucial assumption that the EU meets its cross-border interconnection targets, with some countries acting as net exporters and others as net imports (Figure 1.13). VRE is expected to increase significantly over this timeframe, with 22 countries expected to have a penetration above 50%, and eight countries where peak VRE generation contributes more than 100% of demand, making these interconnections even more critical. In case interconnection targets are not met, the SO&AF concludes that countries will need to increase domestic generating capacity both to meet resource adequacy needs (domestic peak demand) and flexibility needs.

Figure 1.13 • Net importers and exporters under ENTSO-E's "Best Estimate" scenario



Note: Blue means import dependent; Scenario B refers to the "best estimate" scenario, "based on national generation adequacy outlooks prepared by each individual TSO"
Source: ENTSO-E 2015

It is important to note, however, that the generating capacity assumptions that underlie ENTSO-E's TYNDP and SO&AF are based on data provided by member TSOs. With no standardised method for defining resource adequacy, each TSO provides an assessment based on its own perceived requirements. It is not clear whether either exercise would produce the same results if based on a standardized (or harmonised) reliability requirement.

Capacity mechanisms (CMs)

Regardless of their design, CMs share a common goal: ensuring that there is sufficient capacity to maintain resource adequacy. A number of EU member states have introduced, or are considering introducing, CMs of one form or another.[20] Such interventions are generally justified by the

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[19] Demand growth is projected to be 0.8% on average for the entire ENTSO-E region, though peak load grows slightly faster at 0.9%.

[20] The most common types of CMs are targeted, which provide an out-of-market payment to a limited set of capacity resources, or market-wide, which remunerate all resources in the market. In Europe, these are generally referred to as strategic reserves and capacity markets, respectively.

"missing money" problem, where the wholesale market does not provide sufficient revenues for generators to recover their full costs. This is often the result of, or at least exacerbated by, the imposition of price caps on wholesale markets. Most wholesale markets in Europe currently have price caps of some kind. In 2015, however, 12 countries[21] committed to remove direct price caps and to avoid policies that would act as an indirect price cap on markets (Austria et al., 2015).

The European Commission has begun to address the question of how CMs should be established through guidance on public interventions (EC, 2013) and its guidelines on state aid (EC, 2014b). This guidance for the most part aims to ensure that CMs, if introduced, are to the greatest extent possible technology neutral, and that they take into account capacity available in neighbouring jurisdictions. The Commission also say that CMs should not be introduced before first attempting to exhaust the potential for energy efficiency solutions and demand-side flexibility. In addition, jurisdictions looking to introduce CMs must justify why an energy-only market will not, on its own, be sufficient to meet resource adequacy needs.

Regulation of reliability varies across Europe. Some countries – for example, Austria, Germany and Norway – have no reliability standards. Others – such as Finland and the Netherlands – have non-binding targets, and a few, including France and the UK, set explicit, binding targets. These reliability standards are generally probabilistic (that is, based on some expected loss of load), but in two cases (Spain and Sweden) are deterministic – that is, fixed targets (IEA, 2016a).

Sweden and Belgium have both introduced strategic reserves. For Sweden, the maximum size of the reserve is set by the legislature, although the Swedish TSO, Svenska kraftnät (SvK), is allowed to procure less if it determines that a lower quantity of capacity is sufficient. For example, during the 2014-15 winter period SvK procured 1 346 MW of capacity, even though the legal limit was 1 500 MW. The size of Belgium's strategic reserve is also set by the government, through the Federal Ministry of Energy, based on a statistical analysis performed by the TSO, Elia. As in Sweden, the reserve is set in fixed MW terms (unlike the reserve margin requirement generally used in US CMs).

With these mechanisms, capacity in the reserve is only required to be available during months when scarcity events are more likely. In addition, generation inside the reserve is not allowed to participate in the day-ahead wholesale markets. This is done to avoid impacting wholesale prices.

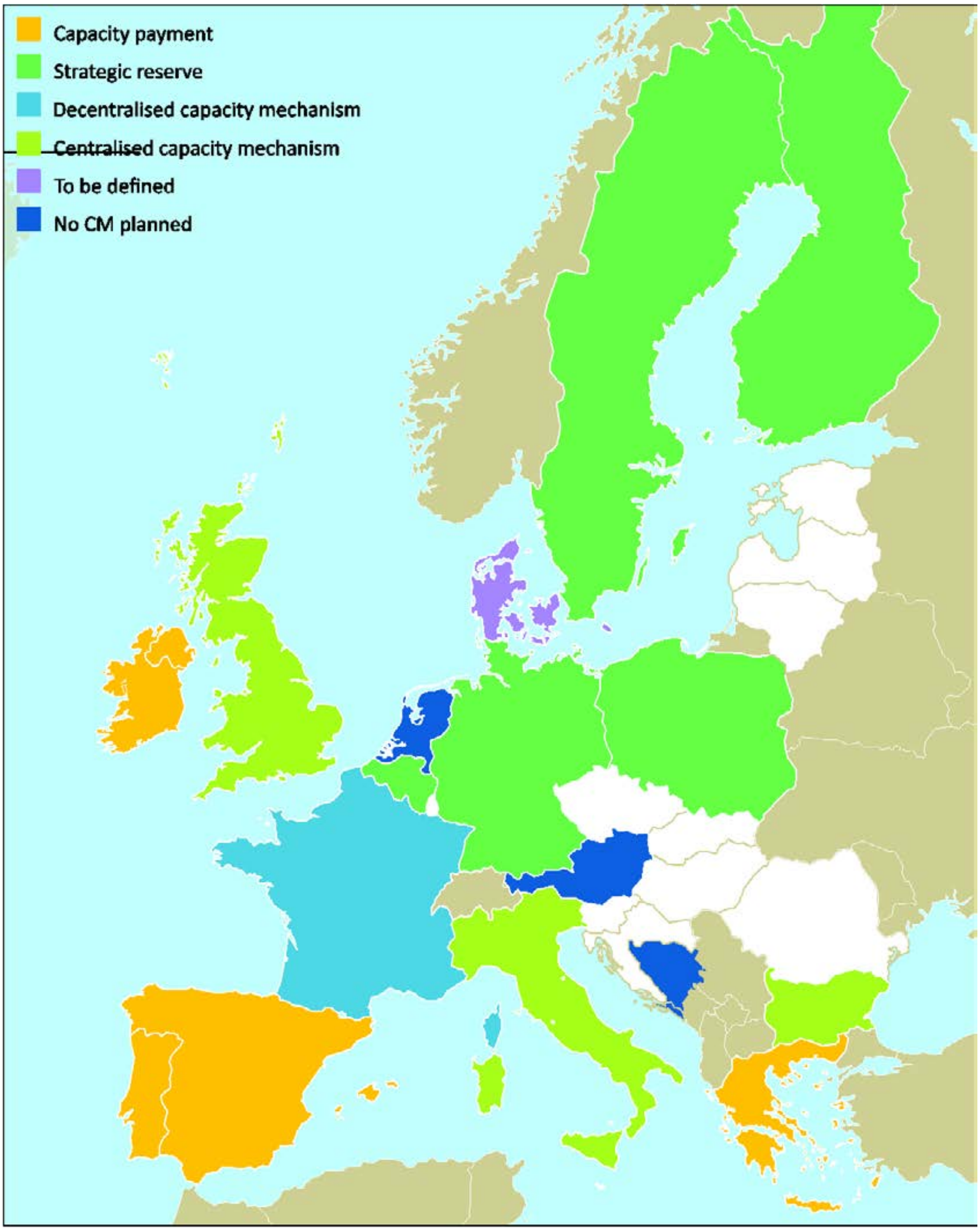
France, Italy and the UK, on the other hand, have all opted to introduce market-wide CMs. These provide a source of revenues for all market participants on top of whatever they might receive from participation in the wholesale market (IEA, 2016a).

In the UK case, neighbouring countries have been eligible to participate in the capacity auctions since the second auction in 2015 (DECC, 2014). As these auctions are forward looking, interconnectors can bid into the auction if they will be commissioned by the 2019/2020 delivery period. This was done by allowing the TSOs of the interconnected markets to bid the interconnector capacity into the auction. Participation by the interconnectors is therefore handled in a somewhat distinct fashion from domestic capacity, which participates on a generator basis.

The French CM has taken a different approach to the inclusion of interconnectors. Here the French TSO, RTE, determines the statistical contribution of existing interconnectors to resource adequacy, and includes that amount in its overall resource adequacy calculation.

[21] Austria, Belgium, Czech Republic, Denmark, France, Germany, Luxembourg, the Netherlands, Norway, Poland, Sweden and Switzerland.

Figure 1.14 • Capacity mechanism experiences in Europe



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area

Greater co-ordination between countries on cross-border flows through day-ahead market coupling raises questions as to how country-specific CMs should interact with one another within the IEM. It also raises issues about whether country-specific CMs are appropriate at all. Similar to efforts to harmonize wholesale markets across borders through market coupling, the Commission is considering how to encourage the harmonisation of CMs (see above discussion on the Winter Package).

At a minimum, the IEA recommends that common EU rules need to be developed for the inclusion of external capacity in domestic mechanisms. If external capacity is excluded completely, the proliferation of national CMs could exacerbate the existing state of general oversupply. If external capacity is included in a non-harmonised fashion, some jurisdictions may incorrectly estimate the amount of external capacity available to meet their reliability needs. There is even the possibility of double counting of capacity.

In this context, the European electricity utility trade association, Eurelectric, has developed a reference model which defines capacity as availability, and considers that cross-border participation in CMs should be seen as a stepping-stone towards regional-scale CMs.

The EU discussion about CM co-ordination is only beginning and is likely to receive increasing attention in coming years.

Conclusion

The EU's efforts to create a single continent-wide electricity market among its member states is the most ambitious such endeavour in the world today. Under the umbrella of market integration, the EU is harmonising regulations across 28 diverse member countries, while also increasing their degree of interconnection and the level of cross-border power trade.

The creation of the IEM) is part and parcel of the EU's broader mission for market integration in all economic sectors, and the path that development of the IEM has taken is a direct result of the EU's institutional framework with its strengths in market regulation and weaker oversight of national decisions on energy and environmental policies. The division of responsibilities between different EU institutions and the 28 member states has resulted in a combination of top-down and bottom-up approaches to market integration and electricity security.

In some cases, this combination of approaches has resulted in notable successes, in particular (though not limited to) the development and ongoing implementation of EU Network Codes and an array of guidelines. It has also led to some challenges, such as divergent national policies on renewable energy support schemes, or the need for and design of CMs. In each case, national policies can have spill over effects that impact cross-border electricity security from both an operations and planning perspective.

Broadly speaking, the EU's efforts at market integration and ensuring cross-border security are a success story. The specifics of the EU process of collaboration and integration are closely tied to the nature of the EU and the relationship between it and its member states, nevertheless, the EU offers an example of how an inclusive process (albeit a complex one) can tackle the linking of historically diverse electricity systems to enhance joint security of supply.

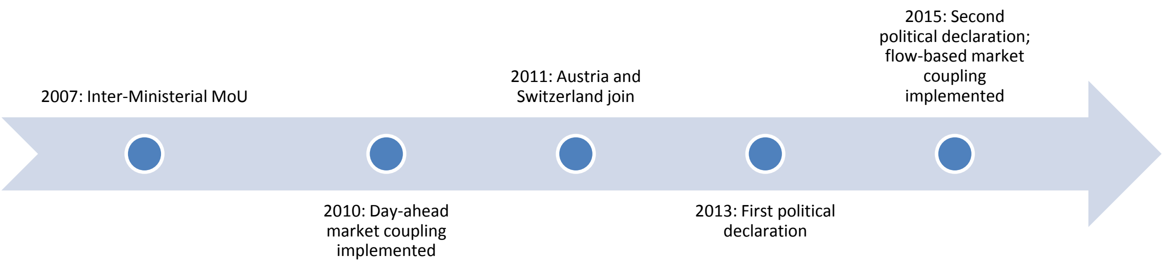
Case Study 2: Regional Approaches to Electricity Security within Europe – the Pentalateral Energy Forum

While the EU level institutions have focused their efforts on creating a single, continental-scale energy market, they have also in parallel encouraged collaboration at the regional level among neighbouring member countries. A primary example of countries working together to meet, or even exceed, EU goals for integration is the Pentalateral Energy Forum (PLEF).

Over the decade or so of its existence, the PLEF has taken on highly ambitious projects, has allowed for close collaboration of market participants in the most interconnected region in Europe, and has also influenced the direction of EU. Many ideas now core to the IEM, such as market coupling, were initially developed within the PLEF.

The PLEF originally consisted of five countries in the CWE region (hence "penta"). Participation has since expanded to seven countries. Recognizing both the value and the challenge of creating the IEM through the existing EU-wide mechanisms for collaboration, the PLEF is attempting to move the market integration project forward at regional level.

Figure 2.1 • Key events in the history of the PLEF



PLEF member countries are obligated to comply with EU energy regulations,[22] but are also free to work on any additional areas of collaboration that may be of interest. The EU takes an active interest in the work of the PLEF.

Key findings

- **The PLEF is made up of well interconnected systems where cooperation is critical to maintain electricity security.** It has provided a forum for governments, TSOs and market participants to collaborate to improve electricity security and manage their rapidly changing power sectors, in particular the impacts of higher penetration of VRE.
- **This bottom-up approach to collaboration has proven capable of leading to meaningful market reforms and improvements in regional security.** Although the work of the PLEF does not carry legal force, many of its outputs have led to the adoption of reform policies by its membership. The PLEF has also allowed Switzerland, a non-member country, an opportunity to engage with EU member countries on critical electricity security issues.
- **The PLEF has set an example for the rest of the EU, acting as a laboratory for reform and innovation.** Concepts first developed by PLEF members, such as market coupling and regional

[22] Switzerland is not an EU member, and so is therefore not obligated to comply with EU regulations. It is precisely for this reason that Switzerland is only an observer of the PLEF, and not a full member.

resource assessments that include probabilistic analysis, have now also been adopted at the EU level.

- **Although close collaboration among the PLEF members has yielded many notable successes, disagreements remain on how to address some aspects of electricity security and market design.** PLEF countries have differing views on the need for capacity mechanisms or how to develop cross-border balancing markets. The PLEF, in its present form, may not be able to fully resolve these differences.

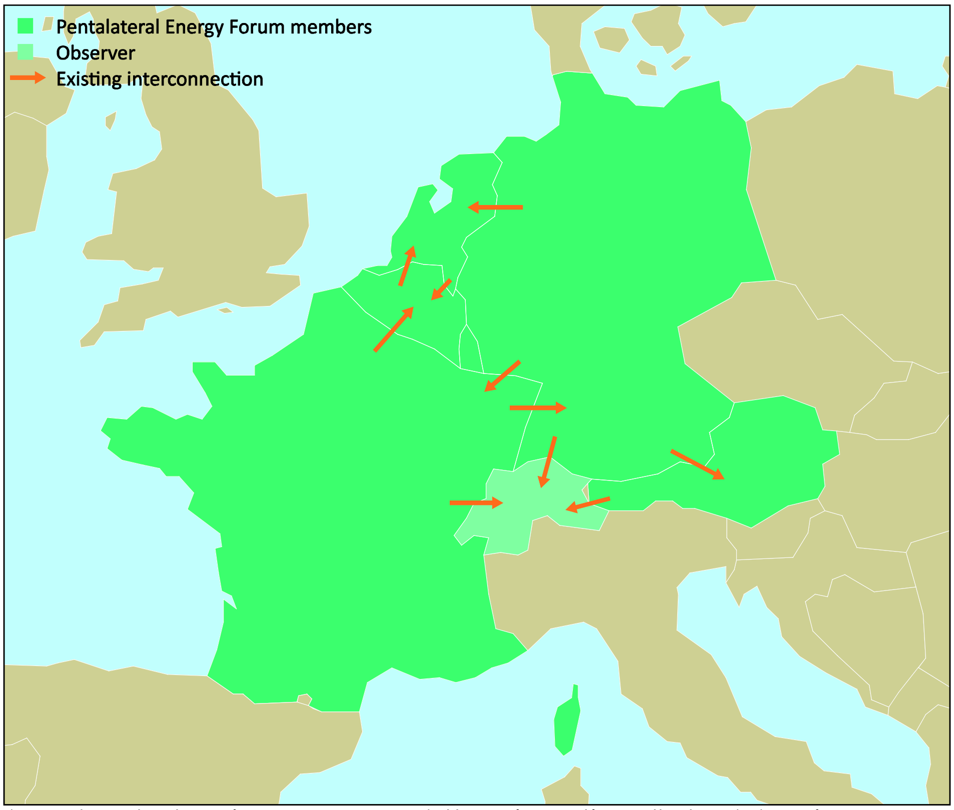
Governance

Forum membership

PLEF membership originally consisted of Belgium, France, Germany, Luxembourg and the Netherlands. In 2011, Austria joined as a member, and Switzerland as an observer.

The PLEF is organized under a "bottom-up" principle, with its authority deriving implicitly from the competent authorities of the member countries. Implementation of PLEF measures is voluntary, and none of the work or recommendations of the PLEF have legal force. Participants include government ministries, TSOs, NRAs, power exchanges, and market participants. The PLEF secretariat is hosted by the Benelux Secretariat General,[23] and is based in Brussels.

Figure 2.2 • Map of PLEF member countries



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Note: The PLEF region is among the most interconnected in Europe. Interconnections included in map are only intended to show the general direction of trade, and not the overall level of interconnection.

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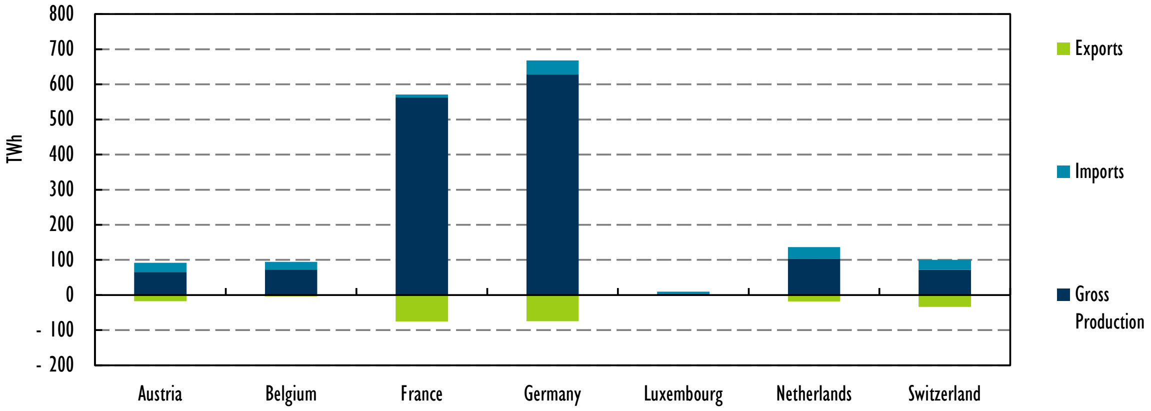
[23] The Benelux Secretariat General is the administrator of the Benelux Union, which is composed of three countries: Belgium, the Netherlands, and Luxembourg.

The countries that make up the PLEF have a long history of collaboration, and, in general, there is consensus among its members on the direction of work. This is reflected in the overall consistency of the work plan over time. Anecdotally, there is sometimes less consensus is on how to prioritise the various elements of the programme.

Figure 2.3 • PLEF member country gross generation, imports and exports, 2014



Source: IEA (2016), Energy Balances of OECD Countries, www.iea.org/statistics

The PLEF MoU, and the First and Second Political Declarations

MoU

The MoU signed in 2007 declared that the five original member countries would collaborate on two topics: market integration and security of supply. Market integration tasks focused on the implementation of flow-based market coupling, including the necessary conditions for its implementation, the governance structure under which it would be developed (in particular, the allocation of responsibilities to the relevant parties), the organisational structure of the working groups, and a timeline for implementation. The conditions for implementation are notable for, among other things, declaring that gate closure times[24] should be harmonised (an area of ongoing discussion for the EU more broadly) and that countries connected to but outside the membership of the PLEF (in particular, Norway and Denmark, though also countries to the east of the PLEF, including, for example, Poland) would also need to be involved, at least at an administrative level. Some of these countries have begun to attend meetings of the various working groups.

Efforts on security of supply covered a broader set of areas, including the development of a regional system adequacy forecast, the harmonisation of how system incidents are defined and reported, the development of a TSO cooperation platform, and the development of a Regional Transmission Capacity (RTC) plan.

First Political Declaration

Having successfully implemented day-ahead market coupling by 2013, the members of the PLEF signed a further First Political Declaration laying out an agenda for future work covering the same two broad areas as the MoU: market integration and security of supply (PLEF, 2013).

[24] Gate closure refers to the point in time when market bids are no longer accepted.

On market integration, the Declaration set a timetable for complete implementation of flow-based market coupling (scheduled for the first quarter of 2014, though full implementation was not completed until 2015) and declared that any efforts would have to be compatible with broader EU work on the subject. In particular, the Declaration noted special efforts should be made to ensure compatibility with market coupling in the Central Eastern European (CEE) region – a region directly impacted by loop and transit flows from the PLEF region, in particular Germany. The Declaration also supported the development of a cross-border intraday market.

On security of supply, the Declaration expands the work of the PLEF beyond transmission planning to include a generation adequacy assessment, with the specific intent of feeding that assessment back into transmission planning by TSOs. The Declaration notes five areas of particular focus:

- Supply-demand balance, and potential impacts on network infrastructure.
- Allowing for greater communication on future infrastructure needs and on how to manage potential bottlenecks.
- Allowing for regular communication on national supply and demand scenarios.
- Collaboration on both national and regional generation adequacy assessments, including the potential impact of national policies such as the implementation of CMs.
- Collaborative work on examining the potential impact on system security of loop and transit flows, increasing penetrations of VRE, and storage.

The First Declaration also notes that the PLEF will continue to support TSOs in their efforts to improve communication and the exchange of data.

Second Political Declaration

A Second Political Declaration signed in 2015 deepened the PLEF governance framework, establishing a Ministerial Conference as the governing body (PLEF, 2015a). This Ministerial Conference sets out the PLEF's primary objectives and also evaluates its work. All decisions of the Ministerial Conference are made by consensus. Responsibility for coordinating and monitoring the day-to-day work of the PLEF is assigned to a Coordinators Committee which includes representatives from the respective Ministries, while responsibility for carrying out the programme of work is given to two Support Groups, made up of representatives from the relevant Ministries, NRAs, TSOs, power exchanges, and other market participants. As participation is voluntary, some organisations participate more actively than others.

The Second Declaration also lays out a work programme for the PLEF. This is organised into three areas of focus: market integration; security of supply; and a new area, flexibility.

Market integration focuses on completing the implementation of the CACM Network Code for the day-ahead market and expanding this to the intraday market – in particular, on improving the implementation of flow-based market coupling and on implementing continuous intraday trading across the CWE region.

Security of supply work focuses on developing a regional approach to addressing concerns over resource adequacy, especially with regard to allowing cross-border participation in CMs. For example, the work plan calls for developing a common framework for responding on a regional basis to scarcity events.

Finally, on flexibility, the work plan calls for an examination of ways to improve the flexibility of power markets in the region. It stops short of making any particular recommendations, however, instead requesting an assessment of existing and proposed methods for improving market flexibility.

Relationship between the Forum and the EU

While none of the PLEF's work has any legal force, EU legislation applies to its members just as it does to other EU member states. The PLEF therefore works to achieve its goals within the context of wider EU efforts.

The relationship, however, is not purely top-down. In fact, the work of the PLEF has been highly influential on the EU and the IEM, in particular as regards to increasing cross-border collaboration and security of supply. The success of the PLEF in this regard is a sign both of the quality of its work and the fact that it does not try to supersede EU efforts at the local level.

Involvement of Switzerland

Switzerland is in a unique position in relation to the EU. It is fully surrounded by, and well interconnected with, EU countries, but is not a member state. Nor does Switzerland have a single blanket agreement governing its relations with the EU (unlike in the case of European Economic Area countries like Norway, see Case Study 3). Instead, Switzerland negotiates separate agreements with the EU for each economic sector.

Negotiations for an EU-Swiss sectoral agreement on electricity began in 2007 and are ongoing. Beyond the complexity of the negotiation process itself, there have been two primary obstacles to progress. First, in 2012 the EU ruled that, on cross-cutting areas such as electricity, EU member states could not negotiate separate bilateral agreements: instead agreements must be negotiated with the EU itself. Second, the EU has declared that, under its founding treaty provisions, an agreement on electricity is not possible if Switzerland places restrictions on the movement of people across its border, in line with the equal status freedom of movement of peoples, goods, services and capital (Fischer et. al., forthcoming).

The resulting limits on Swiss involvement in the IEM are reflected in the Network Codes, where, for example, the CACM explicitly states that Switzerland cannot participate before signing a sectoral agreement. Consequently, Switzerland is unable to participate in flow-based market coupling with the PLEF member states.

Despite this obstacle to full participation, Switzerland is actively involved in the PLEF as an observer. This allows Switzerland to stay actively involved in discussions which may influence or feed into the future direction of the IEM project.

Switzerland co-chairs the PLEF working group on flexibility, and has participated in the PLEF's regional resource adequacy assessment, despite being limited in the degree to which it is integrated into the regional market. Switzerland is a winter peaking country whose large hydroelectric fleet produces mainly in the summer (Swissgrid, 2015). As a result, it is a net importer of electricity during the winter months. Much of its hydroelectric power is in reservoir or pump-storage hydro, which can be sold into the regional day-ahead markets but which can also provide significant flexibility to the system.

System security

Day-ahead market coupling

The EU institutions have often used the levels of price convergence across member states borders as a proxy for measuring market integration.

Historically, cross-border day-ahead prices have rarely converged. This is partially due to transmission constraints which, even if market integration were perfect, would lead to some degree of price divergence. Lack of convergence also, however, reflects the fact that power exchanges in different jurisdictions have historically operated as distinct entities. As a result, not only have prices diverged beyond what would be expected given the level of transmission constraints, at times cross-border power flows have moved in the opposite direction from that which prices would suggest they should.

The EU has adopted market coupling as its preferred method for achieving cross-border price convergence and power flows. This concept originated among the members of the PLEF. At its core, market coupling is simply an algorithm for determining electricity prices and a method for sharing data. The underlying institutional arrangements, including power exchanges, remain separate. This arrangement is therefore different from the true cross-border power market that has been developed among the Nordic countries, which includes, among other things, a single power exchange for the entire region (see Case Study 3).

Market coupling was first introduced among PLEF members in November 2010 for day-ahead markets, and was extended to intraday markets in 2015. There are no plans at present to extend market coupling to the balancing markets. However, making day-ahead and intraday markets more efficient should, in theory, lead to more efficient real-time markets as well.

Under day-ahead market coupling, power exchanges share relevant data with each other, and calculate prices independently using a common algorithm. Thus, market coupling is a "bottom-up" approach to market integration. Data collection and ultimate responsibility for performing the necessary calculations remains the responsibility of the relevant power exchanges, but interconnected markets all work from of a common data set, ensuring consistency. This offers many of the benefits of full market consolidation, without the need to develop common institutions with authorities that extend across jurisdictional boundaries. It does lead to is a certain redundancy in system operations, as procedures that could be performed once for an entire region are instead performed multiple times, but the additional cost of performing these calculations independently is relatively small, and provides a natural check on calculations (if the calculation gives different results in different regions, something has gone wrong in the process).

The PLEF market coupling algorithm accounts for available interconnector capacity, meaning that so long as there is sufficient capacity available, buyers and sellers can be matched across borders. Transmission capacity is allocated through "implicit auctions" – implicit because no market participant explicitly requests use of the interconnector; rather, capacity is simply allocated as needed.

The consistent application of the algorithm has led to power flows that more closely reflect market prices.[25]

Table 2.1 • Percentage of hours in a year when hourly day-ahead prices were equal across select PLEF borders, 2003-11

Border(s)	2003	2004	2005	2006	2007	2008	2009	2010	2011
FR-DE	0%	0%	0%	0%	0%	0%	0%	8%	68%
FRE-DE-NL	NA	NA	NA	0%	0%	0%	0%	8%	63%
FR-NL	NA	NA	NA	4%	60%	66%	54%	58%	67%
NL-DE	NA	NA	NA	0%	0%	0%	0%	12%	87%

Source: IEA, 2014

[25] Of course, real-time power flows can always diverge from day-ahead expectations, simply because real-time supply and demand may not match day-ahead expectations

Flow-based market coupling

Day-ahead market coupling as it was first implemented took interconnector capacity as a fixed value, and then calculated prices and cross-border flows accordingly. Flow-based market coupling attempts to further optimise the use of interconnectors by taking into account a more detailed view of the grid and an improved set of assumptions on VRE generation.

The success of flow-based market coupling is measured across two dimensions. First, coupled markets should see a further increase in price convergence. Second, markets should see an increase in day-ahead price volatility, reflecting the fact that the volatility of VRE generation leads to more volatile market prices.

In addition to shared data and a common algorithm, flow-based market coupling requires a common, detailed model of the grids of all coupled systems. Moreover, it is not enough to simply develop this model and update it periodically. Any change to the grid of any system (for example, unplanned maintenance on an internal transmission line) must be communicated to all relevant parties in a timely manner and the changes must be implemented in all grid models in a consistent fashion. To assist in managing the complexity of this task, Coreso (see Case Study 1, Regional Security Cooperation Initiatives) acts as the coordinating body. System changes and relevant data are sent to Coreso, which updates and distributes the grid model.

While day-ahead market coupling has also now been adopted by regions beyond the PLEF, there are some indications that the additional coordination on data sharing required by flow-based market coupling may act as a barrier to its wider adoption across Europe. In particular, some TSOs argue that there is no legal requirement for sharing the relevant data on grid topology (Eurelectric, 2016). This may be an area where the EU will decide to intervene, if only to encourage NRAs to clarify the legal issues.

Functioning of market coupling in case of capacity shortage

If system information is accurately included, prices in coupled markets should reflect the presence of capacity shortages – whether in generation or transmission capacity. Where there is limited generating capacity in the coupled system but sufficient interconnection capacity, prices should rise throughout the system. Conversely, if there is limited interconnection capacity, the markets should decouple, and prices should rise in the importing market.

This situation may be complicated, however, by market design choices or the responses of TSOs to scarcity events. TSOs have not always reacted to scarcity events in the way the market expects, and any system change made by a TSO that is not visible to all market participants has the potential to undermine the functioning of market coupling. An example of this occurred on 22nd and 23rd September 2015 in Belgium. On the 22nd, prices reached 450 euros per MWh, while the maximum import capacity was 3 000 MW. The next day, import capacity was raised to 4 000 MW and prices dropped to 50 euros per MWh. The problem for market participants was that it was not clear why the capacity limit increased by 1 000 MW, as the system topology seemed unchanged. The explanation was the TSO, seeing the price spike, elected to delay scheduled maintenance on a transmission line, and had adjusted import capacity up to reflect this (CREG, 2016).

Market participants subsequently questioned this decision, arguing that price spikes are the appropriate outcome of scarcity, and that TSOs should base their decisions to change the system topology on system security needs alone. The TSO, on the other hand, argued that it was entirely appropriate to take prices into account when making their decisions (EFET, 2015). Notwithstanding the merits of either argument, the more important issue here is that the decision to change the network topology was taken in a non-transparent fashion. If the grid topology, and the relevant change, had been transmitted to all market participants in an equal fashion, market decisions would have been made accordingly.

This case concerned prices, but it is possible to imagine the situation happening in reverse: where an unexpected change made by the TSO reduces network capacity to below what market participants expect, potentially leading to a shortage of resources.

Intraday market coupling

Market coupling during the intraday period has made less progress than with day-ahead markets. Improving intraday trading across borders is an important component of meeting the flexibility needs of the integrated power system.

The efficiency of intraday power trading has been undermined by explicit allocation of transmission capacity and by differing product definitions and gate closure times.

Under explicit allocation, transmission capacity is allocated on a first-come, first-serve basis, for free, to any party that requests it. Transmission capacity allocation is managed either by the TSO directly or, more often, through the RSCI (see Case Study 1). As a result, the process of capacity allocation is managed separately from the matching of energy bids and offers in the intraday market. Both the fact that transmission capacity is allocated for free and the fact that energy and capacity are allocated separately are potential causes of inefficient allocation and real-time power flows that diverge from scheduled flows (Agora Energiewende, 2016).

Intraday market coupling allows for more efficient use of transmission capacity that remains unused after day-ahead trading is complete. It should also allow cross-border transmission allocation to better reflect expected VRE production, which is easier to predict closer to real-time than 24 hours out. Responsibility for developing the rules for intraday market coupling is shared between the TSO and the power exchange, which develop the methodology for intraday transmission capacity recalculations and pricing, as well as the definition of intraday products. With regard to implementation, however, the TSO is responsible for recalculating intraday transmission capacity, while the power exchange is responsible for the implementation of intraday products (ACER, 2011).

One obstacle to complete implementation of intraday market coupling among PLEF member countries is that their markets have different intraday products. Austria, Germany and Switzerland offer both 60 minute and 15 minute products, while Belgium and the Netherlands only offer 60 minute products. France offers a 30 minute product (Table 2.2)

Table 2.2 • Product definition and gate closure times among the PLEF countries

Country	Product duration (minutes)	Gate closure (minutes)	
		Domestic	Cross-border
Austria	60 and 15	60	60
Belgium	60	5	90 or 150
France	30	30	60
Germany	60 and 15	30	60
The Netherlands	60	5	90 or 150
Switzerland	60 and 15	60	60

Source: IEA research

There is an even greater diversity when it comes to gate closure times. Trading in Switzerland is allowed until 60 minutes before delivery, while Austria, France and Germany all allow trading up to 30 minutes before. Belgium and the Netherlands, meanwhile, allow trading up until 5 minutes before delivery. Cross-border trades, however, are subject to different (longer) gate closure times. Cross-border trades between Austria, France, Germany, and Switzerland are only allowed up to 60 minutes before delivery, and either 90 minutes or 150 minutes between Belgium and the Netherlands, depending on the time of the trade. Gate closure times differ for domestic versus cross-border trades because of differing IT systems across TSOs and the time required to process a scheduled cross-border trade, which is managed differently than domestic scheduling (PLEF, 2016).

True regional intraday market coupling would require that all countries offer the same products, so that bids and offers can be matched across the region across all relevant time frames, and commonly defined gate closures. Harmonising product definitions is a smaller task than harmonising gate closures, however. Either all countries must agree on common gate closure times while still allowing for longer cross-border gate closures (thereby implicitly giving domestic generation priority closer to real-time) or all gate closure times must be made the same (requiring a significant change to the way in which cross-border trades are processed).

Harmonisation of intraday trading is covered under the CACM, which establishes that within a given CCR, the respective NRA or Ministry will designate a Nominated Electricity Market Operator (NEMO). In practice, designated NEMOs have tended to be power exchanges. Nord Pool, for example, acts as the NEMO for day-ahead markets in 12 countries. The NEMO is responsible for managing both day-ahead and intraday market coupling across the designated region. In practice, this means maintaining the market algorithm, relevant procedures, and the IT system for the entire CCR. The CACM also sets standards for cross-border gate closure, declaring that it cannot be more than 60 minutes before delivery. Among the PLEF countries, therefore, only the Netherlands and Belgium are out of compliance.

With the exception of Switzerland, the PLEF countries are required to follow the CACM guidelines. Switzerland will be included through a bilateral agreement. As of the date of writing, the PLEF has ongoing discussions on how to achieve cross-border intraday trade harmonisation, but a plan for implementation has yet to be finalised.

Balancing

The development of cross-jurisdictional balancing within the PLEF region has its origins in Germany. The German power system has four separate TSOs and, before 2008, balancing among the four took place without much in the way of active coordination. Driven by the cost of managing counter-balancing to deal with unexpected cross-border flows (similar, in some ways, to the issue of loop flows discussed in Case Study 1), the German TSOs began voluntarily to coordinate on the purchasing of balancing resources and even went so far as to develop a system-wide merit order. Scheduling of balancing resources was therefore determined collectively, though dispatch decisions remained the responsibility of the individual TSOs.

Balancing coordination beyond national borders is significantly more complex. This is in part because there is greater divergence among the PLEF member countries on real-time (or balancing) products than in the day-ahead or intraday markets, and resolving these differences will likely require significant work if balancing markets are to be extended across borders.

TSOs within the PLEF countries also take differing approaches to how to procure and manage balancing resources. For example, in Austria, Belgium, Germany and the Netherlands, balancing is only managed in real-time, based on actual balancing needs. In France the TSO develops a forecast of balancing needs and begins to activate balancing resources up to an hour ahead of real-time. How balancing services are priced also varies. In Austria, Belgium, France, Germany and Switzerland, balancing services are pay as bid, while in the Netherlands balancing resources are paid based on the marginal clearing bid.

There are three traded balancing products: primary reserves (R1), secondary reserves (R2), and tertiary reserves (R3). Primary reserve products are, for the most part, the same, with most countries offering a 15 minute product. The only country that does not is France, which offers a 30 minute product. For R2, Belgium, the Netherlands and Switzerland each offer 15 minute products, while France again offers a 30 minute product. Austria and Germany however, offer only multi-hour products – 12 hour products for weekdays and 48 hour products for weekends. Finally, for R3, only the Netherlands offers a single, 15 minute product. France again offers a 30 minute product, and Belgium offers a 15 minute product for all resources except demand response (referred to as interruptible load), for which it offers a four-hour product. Austria, Germany, and Switzerland each offer only four-hour products.

Developing a cross-border (or coupled) balancing market would require harmonisation of product definitions across all relevant countries. The increasing penetration of VRE in the region would suggest a move toward more short-duration products. This would require significant changes by TSOs and market participants.

An important potential downside of moving exclusively to short-duration (e.g. 15 minute) products is that this would make participation difficult for certain resources, in particular demand response, which often need longer lead times (in the order of hours) to respond if called into service.

Resource adequacy

As part of its focus on regional electricity security, the PLEF undertakes regional resource adequacy assessments. Notable in part for its inclusion of Switzerland, the PLEF security of supply analysis examined the resource adequacy needs and potential for the winters of 2015/16 and 2020/21 (PLEF, 2015b).

Developing a common assessment did not prove simple, as it required the harmonisation of input data and the development of a common set of agreed upon assumptions. The assessment also attempted to go beyond previous efforts by including a set of probabilistic sensitivities. This differs from the approach traditionally taken by ENTSO-E, which historically has preferred a simpler methodology based on reserve margin assessments. The PLEF assessment now serves as an example to ENTSO-E, which has begun to adopt aspects of the probabilistic approach.

The PLEF assessment's key findings include a recognition that the importance of interconnections for the region will grow because of the expectation that VRE penetrations will continue to increase.

System operators typically measure reliability in the form of loss of load expectation (LOLE), or the amount of time (or number of incidents) where supply is expected not to meet demand over a given time frame. Larger systems with a greater diversity of resources and load are usually better able to ensure resource adequacy. Interconnected systems are, therefore, able to a large degree reduce their LOLE compared to what would be expected if they were isolated systems (Table 2.3). Analysis by the PLEF, for example, found that if France were an island (i.e. if it had no cross-border interconnectors), its LOLE would increase from 14 hours to 217 hours (PLEF, 2015b).

Table 2.3 • Expected LOLE (hours) among the PLEF member countries

Country	2015/2016		2020/201	
	Isolated	Interconnected	Isolated	Interconnected
Austria	117	0	308	0
Belgium	217	14	151	0
France	0	0	3	0
Germany	1 251	0	1 068	0
Luxembourg	1	0	0	0
The Netherlands	0	0	32	0
Switzerland	8 760	0	8 760	0

Source: PLEF, 2015b

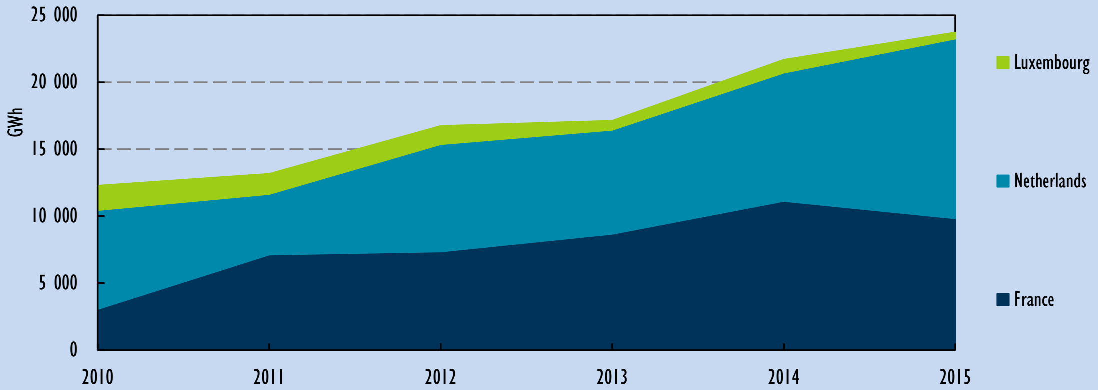
Box 2.1 • Belgium adequacy crisis in the winter of 2014-2015

During winter 2014-15, Belgium was forced to shut down three out of its seven nuclear power units. This exacerbated pre-existing concerns over security of supply, due in large part to retirement of 900 MW of capacity and the announced retirement of an addition 800 MW of capacity.

Prior to the shutdown of the nuclear units, and despite being well interconnected with the rest of the PLEF countries (in particular, France and the Netherlands), Belgium felt the need to implement a strategic reserve – a kind of CM that keeps a fixed amount of capacity (in this case, both generating capacity and demand response) out of the market, to be activated in case of supply scarcity. Initially planned to be 800 MW in total, after the shutdown the size of the strategic reserve was expanded to 1 200 MW.

In order to prevent the creation of the strategic reserve from adversely impacting the wholesale market, Belgium only allowed mothballed units and demand response to participate. The relatively small amount of mothballed capacity in Belgium, however, meant that in essence all mothballed capacity would be procured to be part of the strategic reserve.

Notably Belgium did not include available interconnector capacity when calculating the size of the strategic reserve. At the time, ELIA (the Belgium TSO) estimated a total of 3 500 MW of available NTC between Belgium, France, and the Netherlands, significantly more than what was required to meet adequacy needs. However, the Belgian regulator (CREG) expressed concerns that, in the absence of flow-based market coupling, the process for allocating transmission capacity was not sufficient to ensure that power would flow as needed during a scarcity event. Related to these concerns is the fact that, over the past few years, the level of imports from neighbouring countries has been increasing (see chart below).



Source: IEA (2016), Energy Balances of OECD Countries, www.iea.org/statistics

Today the PLEF is continuing to focus on topics of market integration and security of supply. In addition, the work program includes a focus on flexibility. On security of supply, much of the current work plan will focus on cross-border elements of meeting resource adequacy needs. This includes, for example, harmonising national resource adequacy assessments, developing a common framework for measuring the contribution of cross-border resources in national CMs, and developing a common methodology for responding to scarcity events at a regional level. It also includes an examination of how to develop common reliability standards throughout the region, though it stops short of calling for the implementation of common reliability standards.

The PLEF also intends to look at the cross-border impacts of national resource adequacy measures. In particular, it will focus on national CMs, which historically have been developed with a primarily national focus. Development of CMs among the PLEF countries is uncoordinated, with different countries taking differing views on whether and how to implement them (Case Study 1). Examining how the PLEF member country CM frameworks can be expanded to include interconnections in a harmonized fashion is critical for efficiently meeting regional resource adequacy.

Conclusion

The PLEF is made up of a group of well interconnected and, within Europe, geographically central countries. It is therefore a critical region from the perspective of electricity security. The countries that make up the PLEF are diverse – including one non-EU member country – and have differing views on a number of issues. Nevertheless, through the PLEF seven countries have managed not only to work collaboratively on issues related to electricity security, but also to influence the broader conversation at the European level.

The PLEF has demonstrated that it is possible to enhance cross-border collaboration through a voluntary, bottom-up process. It has also shown that, on topics such as resource adequacy, regions can act as laboratories for innovation, developing some of the tools required to complete the wider IEM.

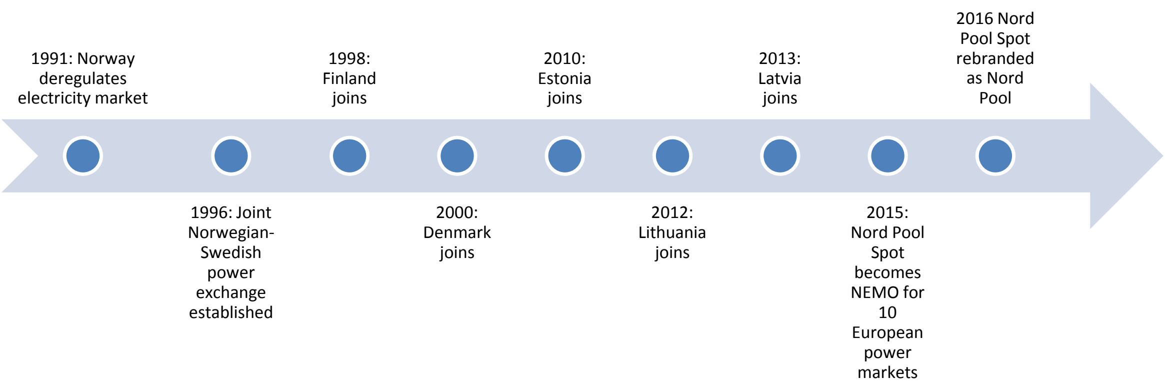
Case Study 3: Electricity security in the Nordic Countries and the Nord Pool Power Market

The Nordic region of Europe[26] has established one of Europe's earliest and deepest efforts at cross-border electricity market integration. The Nord Pool spot market is the most developed cross-border wholesale electricity market in Europe, the success of which derives from broader cooperation across the region on policy issues ranging far beyond energy.

Nordic intergovernmental collaboration through the Nordic Council of Ministers has also led to the co-founding of Nordic Energy Research, which aims to link together industry, researchers, and policy makers to influence energy policy both within the region and across Europe more broadly.

The solid foundation of Nordic cooperation has allowed the Nord Pool market to move farther, faster than the rest of Europe. At the same time this cooperation has remained flexible enough to adapt to EU regulations and to allow for expansion outside of the Nordic region – in particular through the addition of the Baltic States to the Nord Pool market, but also via its trade with the rest of the EU and its participation in the development of other regional institutions, such as the NEMOs.[27]

Figure 3.1 • Key events in the history of Nord Pool



Key findings

- **Nord Pool is the most advanced cross-border power market in Europe**. Developing such an integrated market requires significant levels of collaboration and trust. In the Nordic region, this trust builds on a long history of collaboration on a wide range of policy questions.
- **Though well integrated, the Nord Pool member countries do not make up a truly regional power system.** TSOs remain national, and though there is extensive collaboration at a technical level, decision making and planning continue to be bottom-up processes. For example, capacity mechanisms, where they have been implemented, are country-specific.
- **Nord Pool has proven flexible enough to expand beyond its core Nordic country base through the inclusion of three Baltic Sea countries, and to respond to EU regulations**. In many ways, Nord Pool has been a leader in the conversation on market design and cross-border issues.

[26] Here defined as Denmark, Finland, Norway, and Sweden.

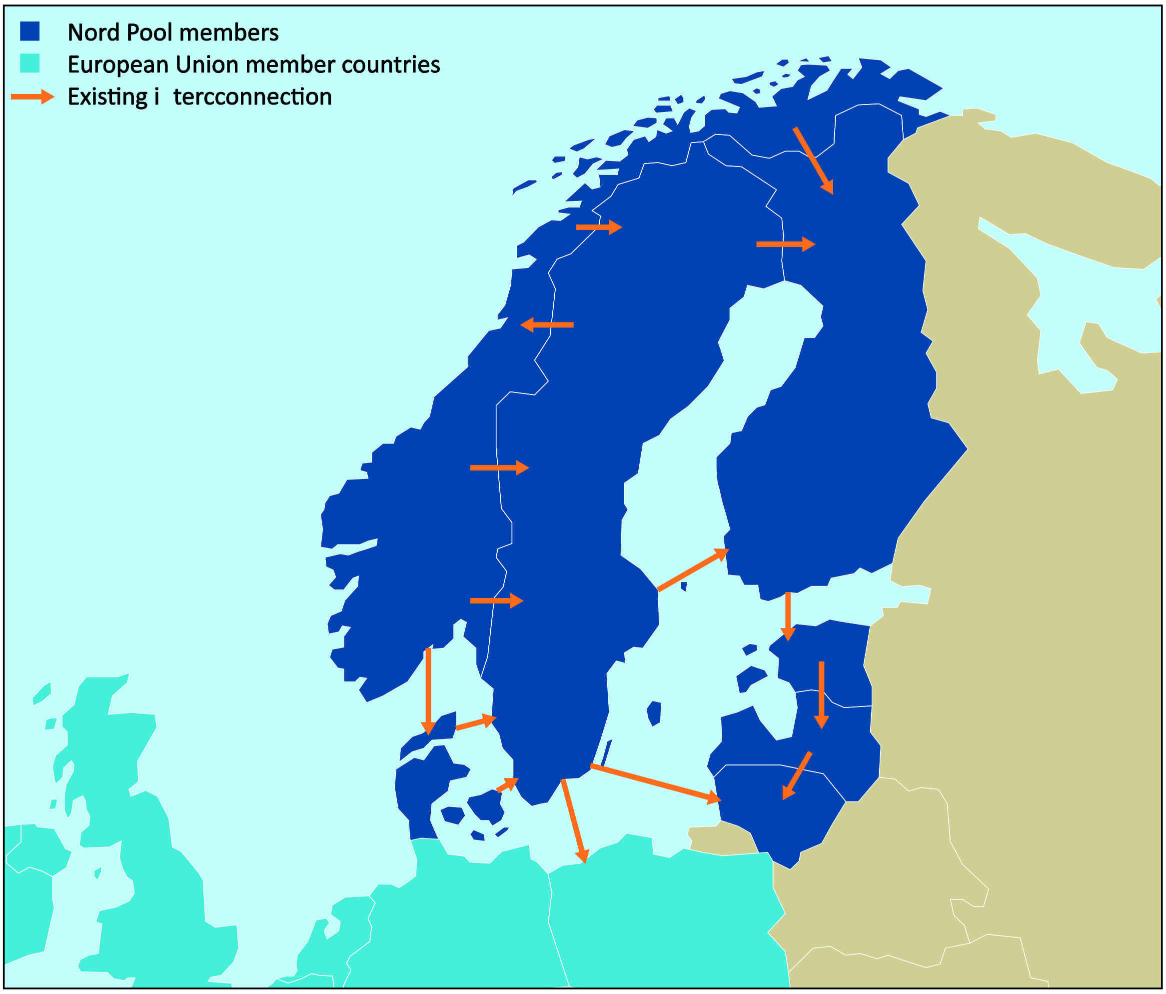
[27] Nominated Electricity Market Operator (see Case Study 2)

Governance

Membership

Formed in 1996 by Norway and Sweden, Nord Pool (formerly Nord Pool Spot) has expanded to a total of seven countries: Denmark, Estonia, Finland, Latvia, Lithuania, Norway, and Sweden. In addition, Nord Pool as a corporate entity has begun to expand into other, non-integrated, markets, and it currently acts as a NEMO in Austria, France, Germany, the United Kingdom, and the Netherlands.

Figure 3.2 • Nord Pool member countries and interconnections

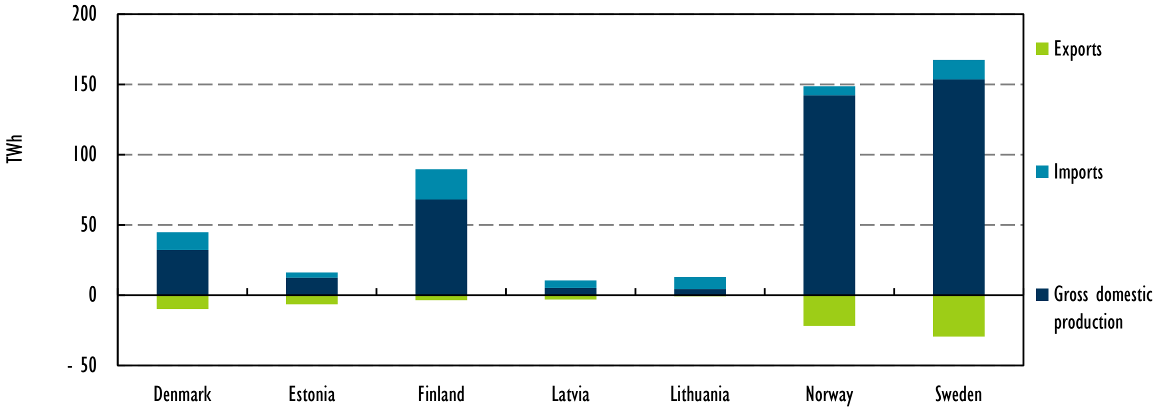


This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Nord Pool is fully owned by the seven TSOs of the Nord Pool region.[28] Initially the TSOs for Norway and Sweden each owned 50% of the corporation. Finland joined in 1999, and Denmark in 2000, and ownership shares were adjusted to 30% each for Norway and Sweden, and 20% each for the Danish and Finnish TSOs. Estonia, Latvia and Lithuania joined in 2010-13, with each of their TSOs obtaining a 2% share in Nord Pool (6% in total, with the remainder split among the four Nordic countries according to the prior proportions).

[28] Energinet.dk in Denmark, Elering in Estonia, Fingrid Oy in Finland, Augstsprieguma tikls in Latvia, Litgrid in Lithuania, Svenska kraftnät in Sweden, and Statnett SF in Norway.

Figure 3.3 • Nord Pool member country gross generation, imports and exports, 2014



Source: IEA (2016), Energy Balances of OECD Countries, www.iea.org/statistics

Common and national institutions

Nord Pool operates a common day-ahead and intraday wholesale market for the Nordic region. All other relevant institutions (TSOs, regulators, etc.) are national. This means, for example, that while all resources in the Nordic region bid into the same common market, real-time decisions such as balancing and long-term transmission planning remain at national level.

Cooperation among Nordic governments on topics related to electricity is managed through the Electricity Market Group (EMG), a working group that functions under the authority of the Nordic Council of Ministers.

The Nordic TSOs biannually publish a Nordic Grid Development Plan (NGDP) along the lines of ENTSO-E's TYNDP,[29] but focusing on the North Sea and Baltic Sea area. The NGDP 2014 examined system needs though to 2030. In addition to similar scenarios to TYNDP 2014, NGDP 2014 also explored sensitivity cases related to: 1) reduced nuclear power capacity in Sweden; 2) delays in project commissioning; and 3) a high renewables case (Green Vision).[30] Under all cases, the region is expected to strengthen and expand interconnectors to export surplus energy to Central Europe.

Nordic TSOs also co-operate on electricity security under the Nordic Contingency Planning and Crisis Management Forum (NordBER). Within NordBER they discuss a range of topics relevant to electricity security including: cross-border contingency planning and emergency response; risk and vulnerability assessments; and resource planning, information sharing and exchanges of experiences. NordBER also organises a common training program.

The Nordic NRAs also cooperate within NordREG, which, in addition to acting as a forum for collaboration on topics relevant to the Nordic countries, also aims to develop "common action to influence the development of the Nordic or the European energy markets" (NordREG, 2016). Energy producers and distributed system operators (DSOs) collaborate through a forum named NordEnergi.

[29] Ten Year Network Development Plan (case study 1)

[30] The development of the Green Vision scenario differed from the TYNDP's high RES scenario in one key aspect. The TYNDP scenario was developed in a top-down fashion by ENTSO-E. In other words, it assumed what a EU-wide high-RES system would look like and imposed the necessary changes on the EU-wide model. The Green Vision scenario, on the other hand, was developed in a bottom-up process, where the individual TSOs determined the changes to the model. The Green Vision scenario is less ambitious in its scope than the TYNDP's high RES scenario.

While the national TSOs remain distinct entities, in 2007 the Nordic Council of Ministers (Norden) commissioned a study on the possibility of creating a common Nordic TSO. Such a TSO would function more along the lines of cross-border RTOs in the US, such as PJM, where planning and operational issues are centralized while local jurisdictional authorities (such as regulation) remain separate. The study did not endorse the creation of a common TSO, arguing instead that the region would be better served by focusing on TSO harmonisation through enhanced cooperation (Norden, 2008).

Historically, lack of a common TSO for the region has not been a hindrance in the development of Nordic area cross-border projects. The first cross-border transmission line in the region was the Nea-Järpströmmen line built in 1960. Physically located mainly in Sweden, its primary beneficiary at the time was Norway. It was made possible primarily because Norway covered more than half the investment cost.

More recently, the Nordic TSOs have indicated a desire to "act as one TSO" to address future challenges including increasing interconnection capacities, greater needs for flexibility and reduced system inertia (Fingrid, 2015). The TSOs have also identified five priority areas for cooperation in the future: security of supply, a robust Nordic power system, better markets, empowering consumers and ensuring a strong Nordic common voice in the EU.

Relationship to the EU

Six of the Nord Pool countries are EU member states. Norway is not an EU member state, but closely cooperates with the EU as a member of the European Economic Area (EEA) which requires that Norway abide by EU regulation on energy, including the Third Package.[31]

Nord Pool membership reinforces Norway's adoption of EU regulations. For example, under the terms set down by the network code on CACM, TSOs in a given region must jointly develop RCSCis (Case Study 1). Nord Pool members are doing this in the form of a Regional Coordination Centre (RCC), to be based in Copenhagen. Even if the impact of the RCC on market operations is small, it would make little sense for Norway to remain a core member of Nord Pool and yet not participate in the RCC.

Several interconnection projects are currently under construction to connect Norway and Denmark to the rest of Europe (Table 3.1). Statnett, the state-owned TSO of Norway, also plans to build two links to Germany and the UK, increasing export capacity by a total of 2 800 MW (Statnett, 2013a). The government has also confirmed plans to allow other companies to build interconnectors in the future. Norway produced 15 TWh of electricity more than it consumed in 2015 and expects new interconnection projects to allow for the export of this domestic surplus (Reuters, 2016).

Table 3.1 • Planned interconnection projects

Interconnection	Country	Capacity (MW)	Target year of commissioning
Nordlink	Norway – Germany	1 400	2020
North Sea Link	Norway – UK	1 400	2021
COBRACable	Denmark – Netherlands	700	2019
Viking Link	Denmark – UK	600 – 700	2020
South Eastern Jutland – Germany Expansion	Denmark – Germany	Expansion from 1 780 to 2 500	2019
Krieger's Flak	Denmark – Germany	400	2018

Source: Statnett 2013b

[31] Iceland and Liechtenstein are also members of the EEA.

System security

Functioning of the wholesale market during scarcity events

Nord Pool operates two cross-border wholesale markets: a day-ahead market (Elspot) and an intraday balancing market (Elbas). Both Elspot and Elbas are physical markets, with Elspot offering hourly products, and Elbas utilising continuous trading.

Although the Nord Pool market sets no explicit cap on electricity prices, there is a technical limit in the Elspot market that prevents prices from rising above of 3 000 Euros per MWh or falling below minus 500 Euros per MWh. This limit is in place to enable the Nord Pool algorithm to find an equilibrium price, and so it is not technically a price cap. In practice, however, it does prevent wholesale prices from rising above 3000 euros per MWh.

No technical limit is placed on intraday trading, though in practice the limits on day-ahead pricing limits the balancing price as well. This situation will likely evolve, as the Nord Pool member countries are subject to the CACM Network Code, which requires that member countries develop a common approach to implementing wholesale market price caps.

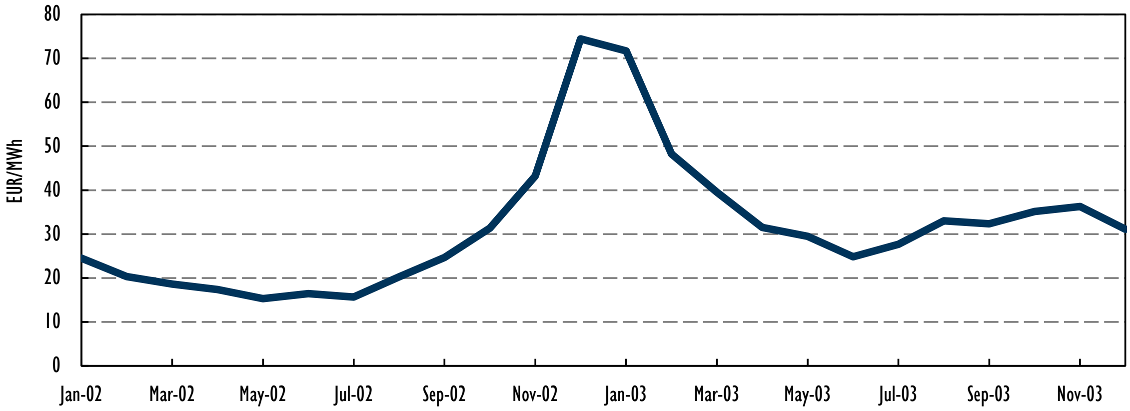
The Elspot technical limit has only been reached on a few occasions, mostly recently in June 2010 when a Danish power plant was taken offline for maintenance at the same time that capacity on a relevant interconnector was reduced. Both of these events were announced in advance, and in theory there was sufficient capacity on both sides of the transmission line to avoid any issues of scarcity. Nevertheless, prices reached the technical limit. The TSOs responded by increasing the limit on the interconnector the following day.

Over the winter of 2009-10, the Nordic region experienced several more traditional scarcity events leading to three price spikes: in December, January, and February, with prices in each case reaching 1 000 EUR per MWh or higher (NordREG, 2011). The initial cause was the loss of approximately 5 000 MW of Swedish nuclear capacity due to summer maintenance on plants not being completed on time, resulting in the Swedish plants functioning at diminished capacity (61% of normal operating capacity, on average) into the winter. Production reached a minimum on 18 December, driving prices to the technical limit. This coincided with a winter that was already colder than average, which in turn led to higher than normal electricity demand. The limited nuclear capacity continued for a period of a few weeks, and on 8 January was exacerbated by a reduction in transmission capacity between south-eastern Norway and Sweden to zero (or close to zero) MW because of higher than anticipated load in Oslo and concerns over domestic system stability and the potential for blackouts. Finally, on 22 February, continued low nuclear production combined with low hydro reservoirs in Norway led to a general state of limited generating capacity. Statnett again reduced transmission capacity, this time to 150 MW, and prices were again pushed to 1 000 EUR per MWh or higher.

In 2011 both Norway and Sweden increased the number of national price zones in order to improve price signals to market participants to better reflect the physical state of the network. This should, in theory, allow for more efficient utilisation of the transmission lines and provide a more market driven response to periods of high congestion.

The winter of 2002-3 offers another interesting example of how the Nord Pool market has handled cases of scarcity. Norway relies significantly on hydropower, and in summer 2002 it experienced an extended period of drought. As a result, by winter Norway had lost the equivalent of 35 TWh of generation, and had to rely on relatively expensive imported electricity in order to meet demand. Wholesale prices rose for a period of months (Figure 3.4).

Figure 3.4 • Average monthly Nord Pool spot price, 2002 and 2003



Source: Nord Pool

A primary concern over this period was that, due to reduced inflows, reservoirs would be insufficiently full by the spring, meaning the period of resource scarcity could extend into the summer months. Norway imposes no requirement on hydroelectric plants to maintain some minimum reservoir level, and high wholesale prices during the winter months could have incentivised hydro plant operators to run their reservoirs down. Instead, however, concerns that their inability to meet future supply obligations would force them to buy power on the spot market in the spring and summer at even higher prices incentivised the operators to do the opposite – restricting their generation in order to maintain sufficient reservoirs to meet future production needs. While there was some discussion after the drought about creating a government mandated minimum reservoir requirement, in the end it was decided that the markets had functioned as intended, and by potentially undermining market decisions such a requirement was likely to do more harm than good.

An additional innovation introduced by Norway after the drought was "energy options". These are in effect commitments for demand reduction that can be procured by the TSO through an auction process. The TSO decides on an annual basis whether or not to procure energy options, and to date it has only done so once (and, in practice, the energy options have never been called into service).

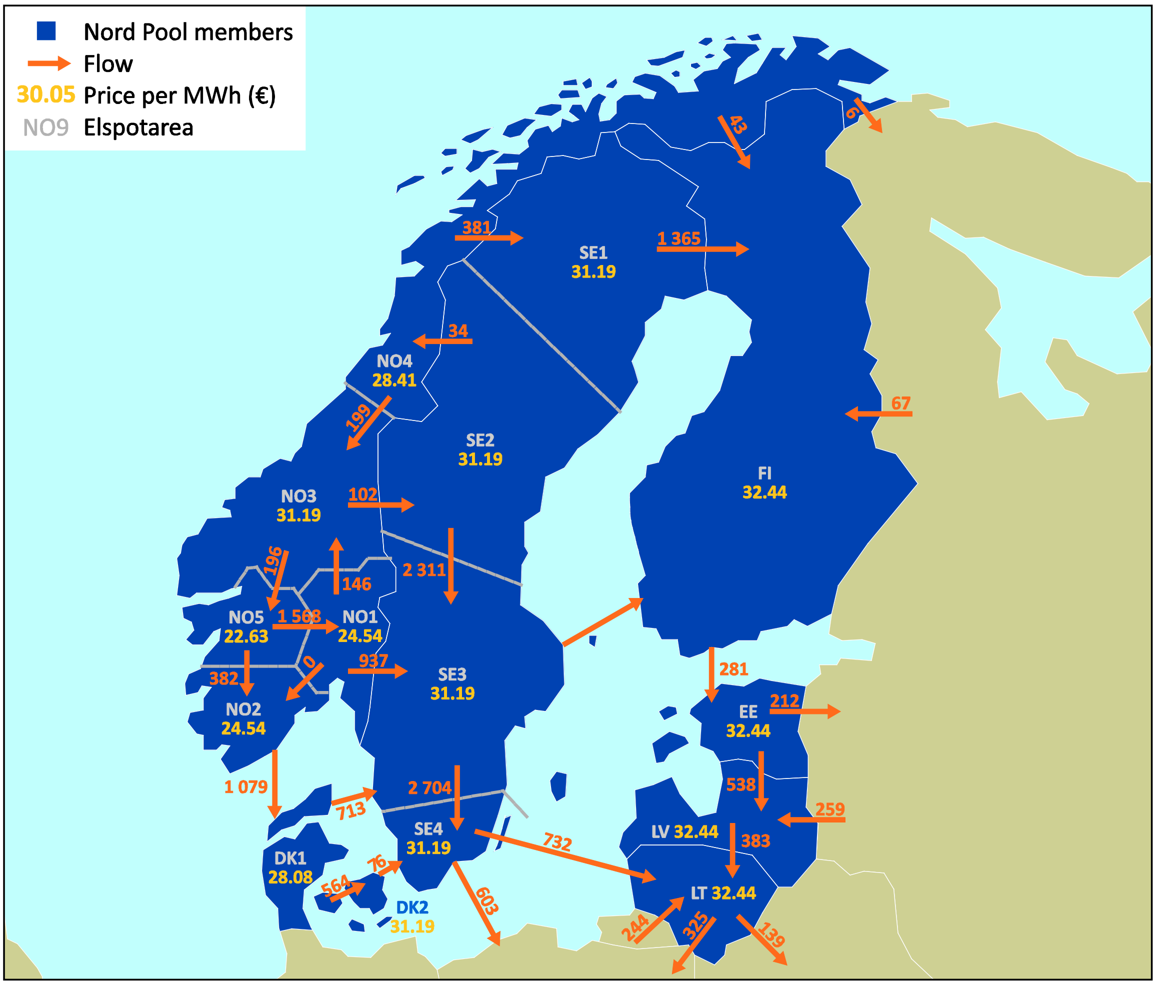
Although balancing and other real-time markets are managed entirely by national TSOs, to take advantage of regional balancing resources, the Nord Pool TSOs maintain a common resource list and develop a common merit order curve. In theory, resources in any given market can meet the balancing needs of any other market, so long as there is sufficient transmission capacity available. Activation of balancing resources, however, is purely the responsibility of the TSO for the country that the resource is located in. In other words, if a TSO in one country (for example, Sweden) wants to activate a balancing resource in a different country (Finland), Sweden's TSO must contact Finland's TSO, which then activates the resource in question.

Sweden-Norway bidding zones

The Nord Pool market is a zonal market, meaning that the market is divided into multiple regions, or zones. Prices between zones may diverge, depending on transmission constraints, but within a zone there is only a single price. Pricing takes place through the common Nord Pool market, but the definition of zones is left to the TSOs. Ideally, zone borders should align with points where the transmission system is constrained. In practice, however, this is not always the case. For example, the border between Norway and Sweden is relatively unconstrained, at least compared to the internal transmission constraints with Norway and Sweden. Yet the zonal boundaries match the political boundaries (Figure 3.5).

In most Nord Pool countries the bidding zone definitions are fixed. The one exception is Norway, which has flexible zone definitions: between 2000 and 2013, Norway's bidding zone definition changed eight times (Statnett, 2013). When the zone definitions are changed, it is Nord Pool's responsibility to adjust the market algorithm appropriately. In practice, this is a relatively simple matter. The challenge is more for market participants, who have less visibility into long-term wholesale prices than they would otherwise.

Figure 3.5 • Example zonal prices and power flows in the Nord Pool market



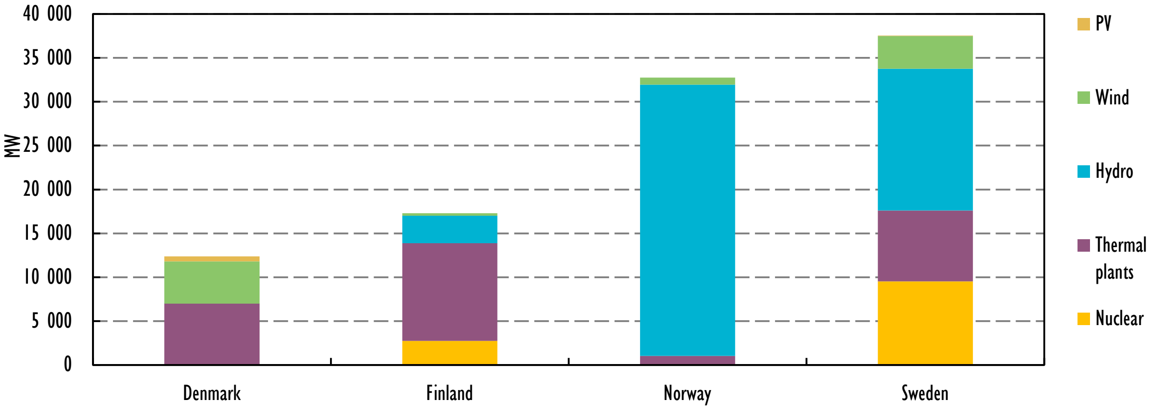
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: Statnett; data from 20/07/2016 at 16:15.

Resource adequacy

Similar to the situation in the rest of Europe, the combination of low or stagnating demand electricity growth and strong growth in renewables has led the Nordic countries to a state of generation oversupply. There are therefore no general resource adequacy issues in Nord Pool, although wholesale prices are depressed and the economics of much of the existing generation fleet is to some extent being undermined. Low wholesale prices also impact plants that remain competitive on a marginal cost basis. Some of the older Norwegian hydro plants, for example, require upgrades or maintenance that are not economic under current conditions.

Figure 3.6 • Installed capacity among the Nordic countries, 2013



Note: Does not reflect seasonal variation of hydroelectric plants, which have reduced capacity in winter, or power plants taken offline but not decommissioned. For example, the Finnish Energy Authority expects total availabe capacity for winter 2016/17 to be 11 500 MW (source: http://www.energiavirasto.fi/documents/10191/0/National+Report+2016+Finland+1518-601-2016.pdf/061a4522-d540-4870-a72c-80ce72a84b15).

Source: NordREG, 2014

The Nordic countries have no reliability standards (neither commonly nor nationally defined) and therefore no resource adequacy target, instead leaving it to the market to decide the appropriate level of investment to meet demand. Each country develops its own independent resource adequacy forecasts, though there is extensive communication across the region and the respective Ministries and TSOs have detailed understandings of the neighbouring systems.

Although there is no common adequacy forecast, regional adequacy assessments have been performed. The most recent was commissioned in 2015 by the Nordic Council of Ministers (Norden, 2015 and focused in particular on whether the energy-only market was sufficient to maintain resource adequacy throughout the region, and, if not, how to improve market design in order to make it so. This was in part a response to the rise of CMs across the rest of Europe and discussions among some Nord Pool members about implementing similar arrangements.

Some Nordic countries (in particular, Sweden and Finland) have implemented strategic reserves or similar mechanisms for ensuring demand can be met in times of scarcity. The Strategic Reserves are designed to operate outside of the wholesale market. Should the TSO in question be unable to meet demand using the resources that cleared in the wholesale market, it adds the entire strategic reserve to the supply curve at a price one Euro cent above the highest market offer (up to the technical limit). In theory this means the strategic reserve has no impact on prices, though of course the mere presence of the reserve can potentially impact investment behaviour in the market more broadly (IEA, 2016a).

Coordination among member countries

Role of Norwegian hydro

Norway is a hydro-dominated power system. Approximately 98% of Norway's 33 GW of installed capacity is hydroelectric. By its nature, hydropower is highly flexible and carbon-free. It is also, however, highly dependent on precipitation levels (and therefore highly susceptible to periods of extended drought). Wholesale electricity prices in Norway reflect this fact to a large degree. When rain levels are high, wholesale prices are low. Because of the interconnected nature of the Nord Pool market, all of the Nordic countries benefit from these low prices. Conversely, when water inflows or reservoirs are low, prices rise. During these periods, Norway will tend to import power from its neighbours, which have primarily thermal based power systems.

Table 3.2 • Size and mean annual production of operational hydroelectric plants in Norway

Size of plant	Number of plants	Total capacity (MW)	Mean annual production (GWh/year)
< 1 MW	554	165	0.8
1 to 10 MW	587	1 989	8.3
10 to 100 MW	255	9 523	43.0
> 100 MW	80	19 273	79.5
Total	**1 476**	**30 960**	**131.6**

Source: Norwegian Water Resources and Energy Directorate (NVE). As of 01/01/2014

Norway's hydro resources play a key role in both the regional balancing market and efforts at decarbonisation. In particular, as many countries in the Nordic region (as throughout Europe) are integrating increasingly higher shares of VRE, Norway is increasingly being called upon to act as a "battery" for the region.

Swedish policies on renewables and nuclear

In 2014, Sweden generated 150.9 TWh, of which 62.2 TWh (41.2%) was from nuclear and 63.9 TWh (42.3%) from hydro. At present Sweden has nine operating nuclear power reactors with a total of 8 849 MW of capacity. The 638 MW Oskarshamn 2 unit has been retired, and three other older reactors by will also close by 2020, removing 2.7 GW net from the system. These decisions are mainly due to diminishing revenues from nuclear plant operations.

The government had imposed a tax on nuclear power of approximately 0.75 euros per kWh. The plant owners argued that the tax hurt profitability at plants already under pressure from low market prices and the need for expensive upgrades to meet new safety standards imposed after the Japan's Fukushima nuclear disaster, and in June 2016 the government agreed to phase it out by 2019. The agreement also allows for the construction of up to ten new nuclear reactors at existing sites to replace aging reactors that will retire.

There is one historical example of the impact of reduced Swedish nuclear capacity on the regional market. Between December 2009 and April 2010, Swedish nuclear capacity was reduced by 5 000 MW due to extended shutdown of several units for maintenance and component replacement work (ThermaNord, 2015). The result was a net inflow of 4.7 TWh in 2009 and 2.1 TWh in 2010. Almost 90% of these imports come from other Nordic countries while the rest are from Poland and Germany.

Sweden and Norway launched a common renewable energy support scheme with Norway in 2012, called "elcertificates", aiming to increase electricity output from such sources as wind, hydropower and biomass by 28.4 terawatt-hours (TWh) by 2020. The increase in subsidised renewable energy in the Nordic countries, however, pushed electricity prices to 15-year lows in 2015, hurting producers, such as Norway's Statkraft or Sweden's Vattenfall. In April 2016, the Norwegian government announced that it is planning to end its participation in the subsidy scheme by 2021 (Reuters, 2016).

Sweden, however, has announced that the electricity certificate system for renewables will be extended and expanded by 18 TWh of new certificates until 2030. From a pure resource adequacy perspective there is sufficient capacity in the region as a whole to meet Sweden's domestic needs. In fact, Sweden could retire the majority of its nuclear fleet and still meet its resource needs, simply by relying on interconnectors to capacity in Norway.

National capacity mechanisms

In 2015, the Nordic Council (Norden) commissioned a study examining how to meet the capacity adequacy needs of the Nordic region (Norden, 2015). The report does not reach a specific conclusion on the need (or lack thereof) for CMs. It does, however, explicitly focus on alternatives to such mechanisms for ensuring resource adequacy. The report points to EU guidelines indicating that alternative measures should be exhausted before a CM is implemented, and therefore focuses on wholesale market reforms (EC, 2013). The report also highlights the potential negative spill over effects of uncoordinated development of CMs, especially among neighbouring countries.

The report found that, in general, there was sufficient capacity throughout the region, both in absolute terms and in terms of generation flexibility, to meet resource adequacy needs until 2030. Most of these were generating resources, however, and the report did advocate doing more to include demand-side resources into the market. It also advocated the implementation of flow-based market coupling and moving to 15 minute products.

While Nordic cooperation on power market development is quite strong, resource adequacy and the question of whether to develop CMs is one area where the region has not reached an easy consensus. In particular, despite the high level of cross-border interconnections, some Nord Pool countries have chosen to implement or are considering implementing CMs. Both Finland and Sweden have strategic reserves (described below). In addition, Denmark announced plans to create a 300 MW strategic reserve for the eastern portion of the grid.[32] The existence of these CMs suggests that, in at least some Nord Pool countries, meeting resource adequacy needs with domestic generation is preferred to relying on imports during scarcity events.

Strategic reserve in Sweden

While Sweden is not as dependent on hydroelectric power as its neighbour Norway, it nevertheless relies on weather-dependent generation to meet a large portion of its generation needs. In 2014, 49% of Swedish demand was met by hydro power, while wind made up more than 7%.

Concerned about overdependence on VRE, in 2003 Sweden introduced a strategic reserve. The maximum size of the reserve (currently 1.5 GW, or 5.7% of Sweden's 26 GW peak demand) is determined by the Swedish legislature. Responsibility for maintaining the reserve, however, lies with Svenska kraftnät (SvK), the TSO. SvK has the right to determine how much capacity it needs, up to the legally defined limit, and can therefore choose to procure less capacity if it is appropriate to do so.

Initially meant to last for just one year, the reserve has been extended numerous times. It is currently planned to last through 2020, and perhaps beyond. Under the current legislation, the strategic reserve is to be wound down by 2020. The capacity limit will be lowered to 750 MW starting in 2017, and to 0 MW from 2020 onward. However, there have been some discussions about extending the reserve beyond 2020.

Capacity in the Swedish reserve is not allowed to participate in the Nord Pool spot market. Activation of capacity in the reserve, however, is explicitly tied to the spot market, as reserve capacity can only be activated if there is not sufficient supply in the market to meet demand. In

[32] Norway technically does not have a capacity market or strategic reserve. However, the TSO does own two mobile gas turbines with a combined capacity of 300 MW for use (with regulatory approval) when the risk of load shedding rises above 50%. As they are intended specifically for grid constrained areas, the generators were considered an alternative to grid investment. Grid investment in recent years has reduced the likelihood of their use, however, and so Statnett has considered selling them off (Norden, 2015)

that case, capacity from the reserve is added to the wholesale market at a price 0.1 EUR per MWh above the last clearing bid (up to the technical limit) until demand is met. Any unused reserve capacity is made available for use in the balancing market, though it again is only activated after all market based resources have been exhausted.

Strategic reserve in Finland

In 2011 Finland passed the Act on Peak Load Reserves to Ensure Balance Between Supply and Demand. More commonly referred to as the Capacity Reserve Act, this gave the Finnish NRA authority to procure sufficient resources to meet peak load, in the form of a strategic reserve. As with the Swedish strategic reserve, the intent of the Finnish reserve is to avoid any impact on wholesale price formation. Resources in the reserve must therefore be kept out of the market, unless and until Nord Pool spot is unable to fully match supply and demand. The regulator was also granted the authority to limit the profits of peaking plants (Finland Energy Authority, 2015).

The size of the strategic reserve is defined by the Energy Authority. Capacity is procured through an open procurement process, the cost of which is recovered through a fee charged to all electricity users.

Finland is a winter peaking country, and so the peak period is defined as being from December until the end of February. During this period plants in the reserve are required to be available with 12 hours' notice. Outside of that period plants must be available within a month's notice.

In 2011 the regulator procured three generating units for the reserve with a combined capacity of 600 MW, under a contract that lasted from 1 October 2011 to 30 June 2013. At that point the reserve needs were found to be lower, and so the strategic reserve was decreased to 365 MW under a two-year contract. Demand response was only allowed to participate starting in the third procurement, which took place in the spring of 2015. A total of 299 MW of capacity was procured, comprised of two generating unit and one demand response unit. The next reserve period will be three years starting in the summer of 2017. The Energy Authority is planning to procure a total of 600 MW.

The total amount of capacity procured in each of these cases is relatively small. However, as in the case of Sweden's reserve, it is notable that only domestic resources are allowed to participate. Due to the seasonal variability of its hydroelectric generation, Finland is unable to meet its annual peak load with domestic resources alone. As a result, it must rely on interconnectors to meet peak demand. For example, in January 2016, imports contributed to 30% of Finland's peak demand needs. As interconnectors are fully utilized during this period, it is not possible to allocate some portion of them to the reserve.

Resource adequacy in Denmark

Across the Nordic regions, Finland and Denmark stand out as being dependent on imports. Finland requires imports in order to meet peak load, while Denmark has a seasonal requirement based on the relative availability of its thermal generation, which tends to be out for maintenance during the summer (Statnett, 2014). More critically, a significant percentage of Denmark's generating fleet is wind. In 2014, wind made up 39% of Denmark's installed capacity. The strong level of interconnections with neighbouring regions (Figure 3.7), in combination with the flexibility of its domestic power system, has enabled Denmark to successfully integrate large quantities of wind generation by offering the opportunity to export power when wind generation exceeds domestic demand, and import power when wind resources are scarce.

Denmark is also notable because it is divided into two distinct grids, one of which (Zealand) is synchronised with the rest of the Nordic states, while the other (Jutland-Funen) is synchronised with the rest of the continent.

Figure 3.7 • Denmark interconnectors, 2014

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: Energinet (2014)

Integration of Baltic countries into the Nord Pool market

Estonia, Latvia and Lithuania (often referred to as the Baltic EU member states) joined the Nord Pool market during 2010 to 2013, after having liberalised their power markets. The Baltic States are well interconnected among themselves, but interconnections with the Nordic countries are somewhat limited. There are only three interconnections: the Estlink 1 and 2 HVDC lines connecting Estonia and Finland, with a combined capacity of 1 000 MW; and NordBalt, a 700 MW HVDC line between Lithuania and Sweden.[33] Nordbalt also helps hydro energy produced in Nordic countries to flow to Lithuania and the other two Baltic countries.

Notably, all of the interconnections with the Nordic countries are DC lines. This is because the AC systems of the Baltic states are synchronised with Russia, and not the rest of continental Europe. Therefore, at present, the only way to trade power with the other members of Nord Pool is through asynchronous connections.

All of these DC links were built under the Baltic Energy Market Integration Plan (BEMIP), an EU initiative launched in 2009 which gave transmission projects connecting the Baltic States to the rest of the EU access to funding under the European Economic Recovery Plan (EERP). This was in

[33] Lithuania is also interconnected with Poland (via a 500 MW HVDC line) and Kaliningrad, both of which are outside the Nord Pool market. In April 2016, however, it was announced that Nord Pool would act as the NEMO for Poland.

addition to what they might receive if the transmission lines were classified as PCI (Case Study 1). Integrating the Baltic States into the Nord Pool market is also a priority under the BEMIP. To this end, the BEMIP includes five specific actions:[34]

- Removing any obstacles to cross-border trade of electricity.
- Reducing cross-border congestion and establishing common electricity reserves.
- Liberalising electricity tariffs.
- Introducing retail competition.
- Establishing a common power exchange for the Nordic and Baltic regions (i.e. Nord Pool).

Each of these goals is seen as key to improving security of supply within both the Baltic region and across the EU more broadly. The BEMIP also includes plans to improve the grid within the Baltic States, in order to reduce internal congestion.

In addition to the near term goal of increasing interconnection with the Nordic states, the BEMIP 2015 action plan includes a longer-term goal of synchronising the Baltic States with the rest of Europe. This would allow the Baltic countries to contribute more actively to the balancing market. Also under consideration is synchronisation with the Nordic region, or becoming a stand-alone synchronous area (ENTSO-E, 2016). Each of these options would require removing all synchronous connections with Russia and Belarus.[35]

Conclusion

Nord Pool is Europe's most advanced effort to create a single, cross-border power market. Collaboration on developing a common power market began earlier in this region than elsewhere in Europe, and in some respects has gone farther as well.

Despite the high level of integration at a market level, the Nordic power system remains somewhat fragmented. The common wholesale market allows for efficient cross-border trading, but TSOs remain in control of national grids, and policies that affect resource adequacy or the generation mix remain firmly in the hands of national policy-makers.

Nevertheless, the Nord Pool market demonstrates that a firm foundation of collaboration can allow for a large degree of cross-border harmonisation and integration, to the benefit of electricity security in the region as a whole. Moreover, such collaboration can be flexible enough to work within (and remain compatible with) the larger EU framework.

[34] https://ec.europa.eu/energy/en/topics/infrastructure/baltic-energy-market-interconnection-plan

[35] Finland and Norway are also interconnected with Russia. Under the Nord Pool market rules, the Finnish TSO is responsible for allocating network capacity available for trading in the day-ahead market. The available capacity is published on the Nord Pool website, though only Nord Pool members who have entered into the appropriate agreements with the Finnish TSO may trade across the Finland-Russia border (Nord Pool Trading Appendix 2g). The interconnection between Norway and Russia is only used for imports, and it is not part of the Nord Pool market.

Acronyms, abbreviations and units of measure

Acronyms and abbreviations

ACER	Agency for the Cooperation of Energy Regulators
ACM	Autoriteit Consument & Markt
BEMIP	Baltic energy market integration plan
BNetzA	Bundesnetzagentur
CACM	capacity allocation and congestion management
CBA	cost benefit assessment
CCR	capacity calculating region
CEE	Central Eastern European
CEER	Council of European Energy Regulators
CEF	connecting Europe facility
CM	capacity mechanism
CREG	Commission de Régulation de l'Électricité et du Gaz
CWE	Central Western Europe
DSO	distribution system operator
EC	European Commission
EEA	European economic area
EMG	Electricity Market Group
ERGEG	European regulators group for electricity and gas
EU	European Union
FERC	Federal Energy Regulatory Commission
GIPL	gas interconnection between Poland and Lithuania
IEM	internal energy market
ISO	independent system operator
ITO	independent transmission operator
LitPol	electricity interconnection between Poland and Lithuania
LOLE	loss of load expectation
NDSG	network development stakeholder group
NEMO	nominated electricity market operator
NERC	North American Electric Reliability Corporation
NGDP	Nordic Grid Development Plan
NGO	non-government organisation
NordBER	Nordic Contingency Planning and Crisis Management Forum
NRA	national regulatory authority
NTC	net transfer capacity
NVE	Norwegian Water Resources and Energy Directorate
NWE	North West Europe
OU	ownership unbundling
PCIs	projects of comment interest
PLEF	Pentalateral Energy Forum
RCC	regional coordination centre
REMIT	regulation on wholesale energy market integrity and transparency
R1	primary reserves
R2	secondary reserves
R3	tertiary reserves
ROC	regional operating centre

RSCI	regional security cooperation initiative
RSCSP	regional system coordination service provider
RTC	regional transmission capacity
SEE	South East Europe
SO&AF	scenario outlook and adequacy forecast
SONI	system operator of Northern Ireland
SoS	security of supply
SR	strategic reserve
SvK	Svenska kraftnät
SWE	South West Europe
TENs	trans-European networks
TEU	treaty on European Union
TFEU	treaty on the functioning of the European Union
TRM	transmission reliability margin
TSO	transmission system operator
TTC	total transmission capacity
TYNDP	Ten Year Network Development Plan
UK	United Kingdom
US	United States
VRE	variable renewable energy

Units of measure

GW	gigawatt
GWh	gigawatt-hour
MW	megawatt
MWh	megawatt-hour
TWh	terawatt-hour

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