ERIA-DP-2016-26

ERIA Discussion Paper Series

A review on Institutional Framework, Principles, and Key Elements for Integrated Electricity Market: Implications for ASEAN

Tsani Fauziah RAKHMAH

Economic Research Institute for ASEAN and East Asia, Indonesia

Yanfei LI

Economic Research Institute for ASEAN and East Asia, Indonesia

October 2016

Abstract: ASEAN member countries are becoming large energy consumers and growing participants in the global energy market. Cross-border electricity trade becomes increasingly important particularly in the context of fast-rising energy demand and growing urban population. This paper attempts to set out the common principles, methodologies, institutions, and structure for designing an integrated cross-border electricity market and delivering practical policy implications for ASEAN. To allow cross-border electricity trade, the region will need a target model, common vision, and principles that govern electricity market and grid operation. In the country level, energy prices administratively determined by the government should be shifted to market-oriented pricing mechanism. Integrated electricity market has an enormous potential that can be realised at reasonable costs. When individual countries pursue regional cooperation mechanism to secure their energy supply, investment comes and contributes to optimisation of available energy resources throughout the region.

Keywords: electricity market, operational planning, ASEAN, European Union

JEL Classification: N75, Q40, Q48

1. Background

This paper reviews the European electricity market, an integrated electricity market of ten national or regional electricity markets and the best model for cross-border electricity market integration. It aims to gain enabling insights into the common principles, methodologies, institutions, and structure for designing an integrated cross-border electricity market and delivering practical policy implications for Southeast Asia.

The idea of pooling energy sources in Europe has been developed since the 1950s. In 1951, six countries agreed to work toward the integration of two major sectors of the economy: coal and steel. Accordingly, the European Coal and Steel Community was formed to create a single market for energy resources and pave the way for a greater economic cooperation. However, it was also acknowledged that coal would be replaced by nuclear energy as the underlying driver for economic growth. The European Atomic Energy Community was introduced in 1957 to create a common market for nuclear power. These regional energy cooperation initiatives advocate close collaboration on energy issues among European Union member states.

The increasing concern for energy supply security has pushed the EU member states to formulate a common energy policy that allows energy to flow freely across borders. The Lisbon Treaty and the adoption of the Third Energy Package gave a clear commitment to the completion of the Internal Energy Market by 2014, allowing free flow of gas and electricity across borders. In 2006, the EU created seven regional electricity markets, marking an interim step toward the future target of a single European electricity market where energy would be traded freely across borders. The seven regional markets are France-UK-Ireland, Central-East, Central-West, Central-South, South West, Baltic, and Northern market (IIEA, 2014). Free cross-border trade of energy was to expand the wholesale electricity competition that would in turn allow electricity to be produced at lower prices for consumers through more efficient use of resources. More competition in the electricity market would provide more choices for businesses and consumers, which would further bring down electricity cost. It was also perceived that a larger and more connected market could address the energy security issues with a resilience power network providing fast access to electricity during the crisis. Peripheral states, such as Ireland, would benefit from this single electricity market.

The single European electricity market has been considered as an effective tool to meet the objectives of EU climate and energy policy that includes achieving security of supply, creating a competitive internal electricity market, and decarbonising the electricity sector through promotion of low carbon and renewable energy as well as energy efficiency. To create an integrated European electricity market, the European commission has allocated up to €6 billion until 2020 (IIEA, 2014). Upgrading power grids to allow the integration with renewable energy sources is also important to bring cleaner power to consumers. Nevertheless, physical connections alone mean nothing for a single electricity market unless all individual markets can trade electricity on the same rules. Therefore, the European Commission needs to harmonise the market rules on institutional connectivity to establish a real power exchange where electricity can be traded across borders.

This paper aims to explore the institutional arrangements that harmonise the operations of cross-border electricity network and coordinate the allocation of responsibilities and compensations of an integrated electricity market. It highlights specific example of the single European electricity market perceived as the most well-integrated and well-functioning cross-border competitive electricity market. This paper begins by outlining the basic principles of electricity market liberalisation and how electricity market is structured in general (section 2). Section 3 then discusses the legislative and regulatory frameworks of the European single electricity market operation. A range of frameworks and regulations are then set out. Section 4 explores the operation of the European electricity market by detailing the mechanisms on how transmission capacity is calculated and allocated among the market participants. This section also discusses grid balancing and compensation mechanism for cross-border electricity flows. Section 5 examines the Ten-Year Development Plan 2014 that outlines the planning and investment of electricity infrastructure that enable the market integration. The last part concludes the paper and summarises the lessons that can be taken from the experience of European electricity market to achieve a single electricity market in Southeast Asia.

2. Basic Principles

2.1. Electricity Market Liberalisation Objectives

Before the liberalisation[1] of the electricity market in Europe, the value chain of electricity mainly included production, transmission, and distribution. After the liberalisation of electricity market in Europe, the energy value chain has been developed to electricity production, trade (transmission), and distribution to the end consumers. Electricity market liberalisation has become one of the main objectives of the EU electricity market integration, for which the underpinning economic principle is the promotion of effective competition. In modern industrialised economies, promoting effective competition in energy market is crucial as energy prices and availability to support production processes, economic growth, and consumer welfare are considered to be playing important role (Ruska and Simila, 2011). For a single electricity market to achieve market liberalisation, the integrated electricity market should be designed to promote free cross-border traded energy that provides incentives for energy suppliers to work out ways to lower their cost of energy production. This competition pressure will lead to power being sourced from the market where it is cheaper to produce (Jamasb and Pollitt, 2005). As a result, prices of electricity will converge towards a competitive price that is also imply as the price of the most efficient supplier. This price convergence delivers direct benefits to consumers in terms of increased surplus. For firms, competitive market provides protection from abuse of market power by dominant firms. Pressures of competition also push suppliers to produce a desired level of product quality demanded by consumers (Böckers et al., 2013).

A perfectly competitive market is an ideal structure that leads to efficient resource allocation as perfectly competitive firms choose output that maximises their economic profit. In the short-run, this will create market price equal to the short-run marginal cost. As long-run adjustment for firms entering and exiting the market could maximise profits, it will in turn create long-run equilibrium (Hopenhayn, 1992). Therefore, in the long run, both market price and marginal cost at the minimum efficient scale of production will be equal, which suggests that resource has been

[1] For a comprehensive review of the history of the European electricity market, one can refer to Li et al. (2016).

efficiently allocated (Cavaliere et al., 2013). As electricity cannot be stored in large amount, energy production (supply) and consumption (demand) have to be balanced all the time to reflect an efficient resource allocation (Böckers et al., 2013).

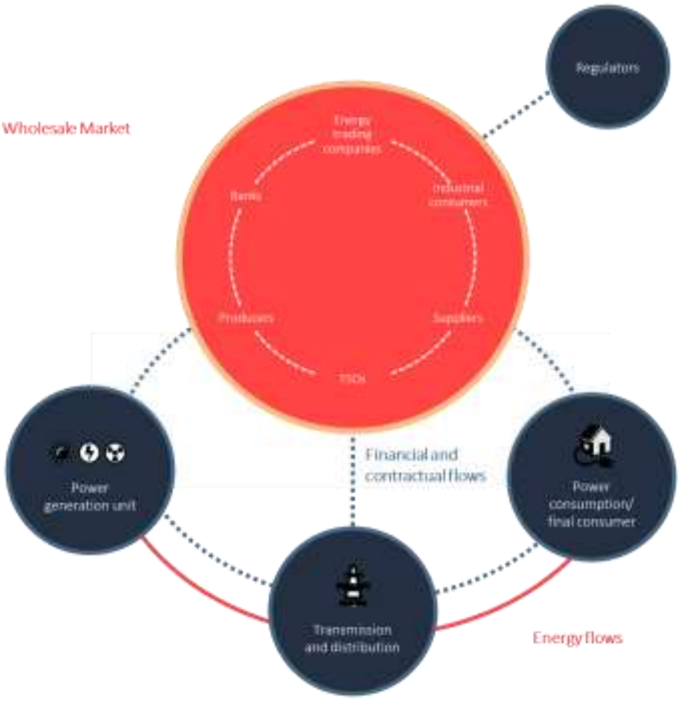
Another objective of electricity market integration among the EU member states is to maintain security of supply through increased transmission capacity. Integrated electricity market connects different national high-voltage grids that further allow cross-border energy trade. Thus, reserves in generation capacity could be shared among buyers within different regions and, consequently, increase supply security (Bekaert et al., 2009). In the face of tremendous challenges such as supply intermittency and increasing peak demand, securing electricity supply is crucial to achieve competitiveness in the electricity market. Cross-border interconnection should be further developed to create supply security at the most competitive price. Market liberalisation leads to higher price transparency and stronger competition among energy suppliers that eventually leads to the creation of advanced cross-border integration and increased transmission capacity (Pidlisna, 2014).

Electricity market integration is important to better achieve the EU’s climate and energy policy target of decarbonising the electricity sector. A well-integrated electricity market is central in enabling secure integration of new generation sources (particularly renewable energy) in a cost-efficient way. Increasing renewable energy sources in the electricity-generation mix will help achieve the EU’s goal of carbon emissions reduction. Competition in electricity market could provide financial incentives for renewable technology innovation and deployment. The efficiency gained from such market can be translated into reduced fossil fuel use, less carbon emissions, and fewer power plants installed.

2.2. Market Structure

Producers of electricity generate energy in their power-generation units and electricity is subsequently transmitted and distributed to consumers through Transmission System Operators (TSOs). In turn, consumers purchase electricity from suppliers who provide them the necessary amount they need. Suppliers can either sell electricity or purchase it in the wholesale electricity market, where different types of market participants buy and sell electricity. Figure 1 illustrates how market participants interact in the wholesale market. In many cases, electricity generated by producers is unlikely to be delivered directly to end-use buyers. Mostly, a single megawatt is bought and resold a number of times before it is used. Such transactions make up the wholesale electricity market and are considered as ‘sales for resale’ (Imran and Kockar, 2014). The wholesale business is open to anyone who can generate power (after securing the necessary approval), connect to the grid, and then find buyers. Companies that produce or import electricity sell it in the wholesale markets. Electricity consumers (e.g. industrial consumers and households) or companies have customers that consume electricity (e.g. suppliers) and buy electricity they require in the wholesale markets. Besides that, some companies primarily focus on trading (e.g. banks and energy trading companies). All these market participants trade in the wholesale market to optimise assets, manage risks, provide liquidity, and speculate on the market movements. The liberalisation of electricity market has caused the emergence of energy trading and power exchanges that operate electricity markets. Broadly, the Agency for the Cooperation of Energy Regulators (ACER) acts as a regulator that monitors the functioning of electricity market and wholesale energy trading (Figure 1).

Figure 1: The Organised Market: Principles



TSO = transmission system operator.
Source: EPEX Spot.

Previously in many European countries, the state regulated the entire power supply system including electricity price. Subsequently after market opening/liberalisation, trading in the wholesale market occurs within cross-border interconnections. Due to the cross-border nature of an integrated electricity market, the wholesale market is regulated across states to ensure a uniform operation of the power system. At the same time, new competing electricity producers and traders are entering the market. Furthermore, suppliers in the wholesale market compete with each other to offer innovative pricing arrangements and services for customers. Only in liberalised market will prices converge toward a competitive price.

3. Legislative and Regulatory Framework

The highest priority of the European Commission on energy and climate is to ensure that Europe has a secure, affordable, and climate-friendly energy without going in details into market design. While this appears plausible, market institutions and the organisation of trading arrangements practically constitute a fundamental issue for common electricity market rules. The lack of common guidelines has resulted in the creation of a wide range of trading arrangements in each member state. Some member states have left trading arrangements to private initiatives in the market while other governments have directly created the market institution. Consequently, electricity has become not tradable across borders, forcing Europe to move from monopoly situations to a decentralised competitive market. This situation has led to the creation of a common market rule to push forward market liberalisation.

The European Commission has adopted a set of directives and regulations known as the Third Energy Package. The legislative package, which came into law on 3 March 2011, aims to foster a more harmonised integrated energy market in Europe. The package aims to improve the way internal energy market functions and to address structural issues. Generally, the package consists of two directives and three regulations concerning common rules for internal energy market and access to the network for cross-border electricity exchange. The Third Energy Package attempts to reform five main areas. First, the ownership unbundling that stipulates separation of energy suppliers from network operators. Second, strengthening the independence of regulators to generate a competitive internal energy market and to ensure that regulations are fairly implemented and enforced. Third, the establishment of ACER that plays a central role in encouraging electricity market integration and enhancing competition through the development of EU-wide network and market rules. Fourth, the cross-border cooperation between TSO and the creation of the European Network of Transmission System Operators for Electricity (ENTSO-E). Fifth, increased transparency in retail markets to benefit consumers (EC, 2016).

Accordingly, this package led to the establishment of ACER and ENTSO-E. ACER provides a non-binding framework for electricity market integration in the EU, which serves as a base for drafting network codes that are further developed by ENTSO-E. Network code is a set of arrangements that govern how market participants generate, trade, and consume electricity for an effective integrated electricity market. Network codes cover technical, physical, operation interconnectivity, and market design fundamentals. ENTSO-E is currently working on ten network codes: (i) capacity allocation and congestion management, (ii) requirements for generators, (iii) electricity balancing, (iv) forward capacity allocation, (v) demand connection, (vi) operational security (merged into the system operation guideline), (vii) operational planning and scheduling (merged into the system operation guideline), (viii) load frequency control and reserves (merged into the system operation guideline), (ix) high-voltage direct current (HVDC) connections, and (x) emergency and restoration.

Figure 2 demonstrates the progress made in delivering the network codes. However, a significant delay in adopting the codes has become a crucial concern. Progress in completing the internal electricity market should emphasise the implementation of existing arrangements in a timely manner. Figure 2 shows the network codes status as of February 2016. CACM and Requirements for Generators are two network codes that are already enforced (ENTSO-E, 2016).

Figure 2: Network Codes Status (as of February 2016)

CACM = capacity allocation and congestion management, DCC = demand connection code, ECB = electricity control board, ECBC = Energy Conservation Building Code, FCA = forward capacity allocation, HVDC = high-voltage direct current, Rfg = requirements for grid connection. *Source*: ENTSO-E, 2016.

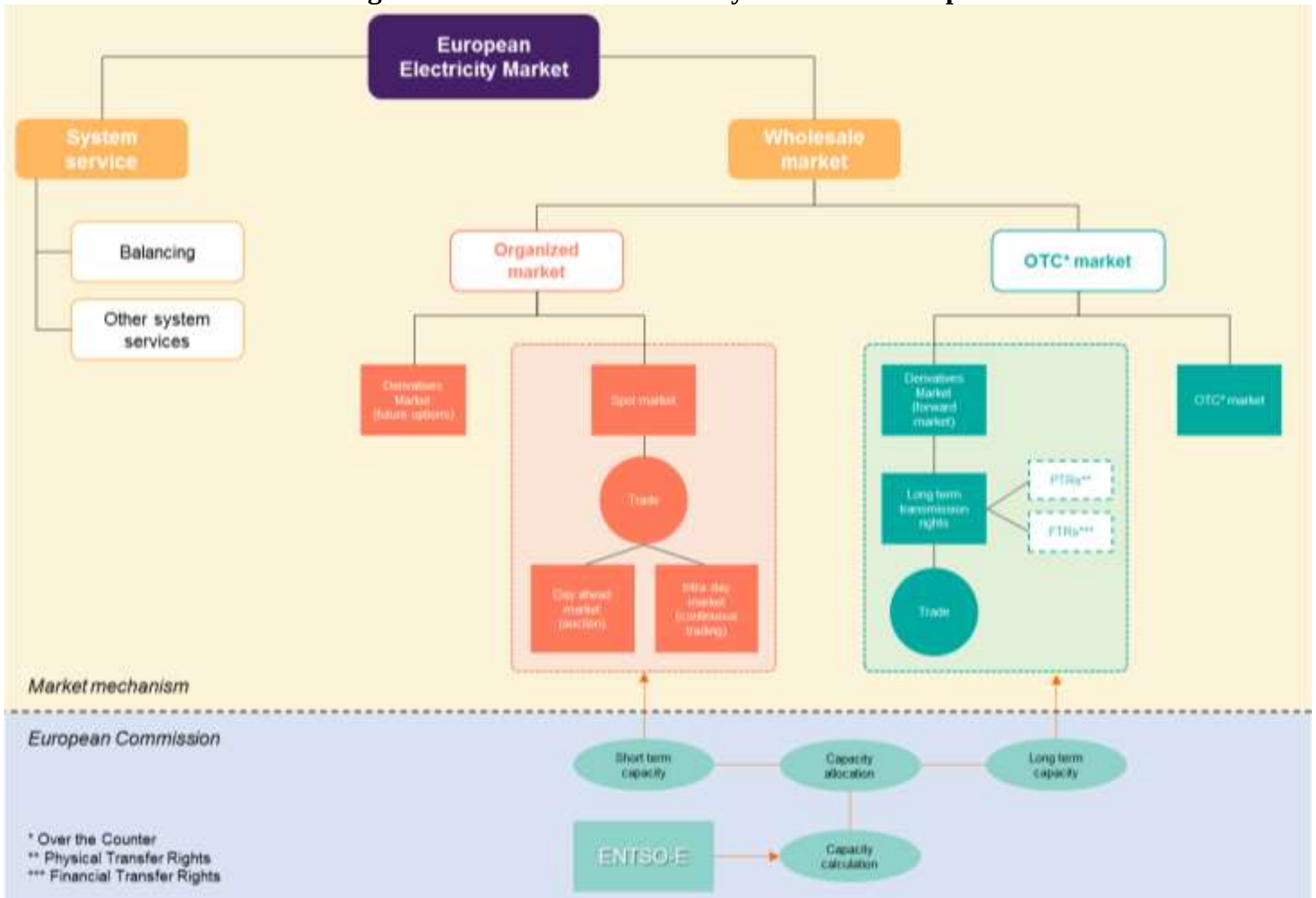
4. Market Operation

4.1 Electricity Market

In general, the current electricity market in Europe is divided into two main components: wholesale market and system service (Figure 3). The wholesale market allows electricity generators, retailers, large consumers, and other financial intermediaries to buy and sell electricity either through organised market or over-the-counter (OTC) type of markets. In OTC markets, electricity is traded between two parties under a bilateral arrangement that includes negotiation of products, volume, price, and delivery period. Under such arrangement, electricity can also be traded in derivatives market (forward market) where suppliers buy and use long-term and forward contracts in advance to cover their consumption portfolio. Forward contracts are for delivering or consuming a particular amount of electricity for an agreed-upon price. Forward markets aim to reduce risk associated with electricity price hike and to secure electricity supply for future consumption (ENTSO-E, 2013), a behaviour called hedging. These markets are crucial for electricity generation to ensure future sales and reduce vulnerability to possible decline of electricity price. Likewise for consumers (particularly for large industries), forward markets are important to secure their future electricity needs at upfront known costs and reduce their vulnerability to possible electricity price hike.

However, as real consumption is not completely predictable and due to the non-storable characteristic of electricity, an organised market is also needed where additional daily and even hourly contracts are traded. Electricity trade for such consumption takes place in a spot market where real-time price is set based on system operation status that reflects the needs of congestions and/or balancing power in the transmission system (Möller et al., 2011). If there is no congestion or imbalance, the real time price equals the day-ahead spot price of the operational hour. In the ideal case with hourly real time market, market participants respond to the price signal and adjust their real time electricity generation and consumption, balancing the grid, and minimising the need for balancing services (Ding et al., 2013). The following subsections explain in details spot market and derivatives market (forward market).

Figure 3: Structure of Electricity Market in Europe



ENTSO-E = European Network of Transmission System Operators for Electricity.
Source: Authors.

4.2. Capacity Calculation by TSOs

ENTSO-E represents 41 electricity TSOs from 34 countries across Europe and is mandated to promote cooperation among TSOs to assist in the development of pan-European electricity transmission network. For the liberalised electricity markets to work properly, calculating the available cross-border capacity needs to be coordinated. In general, TSOs calculate the available and long-term capacity. The available cross-border capacity is one of the key inputs for further capacity calculation. The network code on capacity allocation congestion management (CACM) regulates how available capacity is traded. A well-functioning market also depends on an efficient long-term capacity calculation that incorporates the needs of market participants and system security. The network code which regulates long-term capacity trade is called the forward capacity allocation (FCA). For these calculations, TSOs establish a common grid model based on individual grid model from each TSO. The common grid model incorporates estimates on generation, hourly load, and network status (EC, 2015).

The available cross-border capacity is typically calculated according to the flow-based calculation method or based on coordinated net transfer capacity (NTC). The flow-based approach determines physical margins on each transmission lines that are likely to become congested and their influencing factors, e.g. how each critical transmission line is affected or how it affects another critical transmission line. It normally allows an increase in cross-border transmission capacity where it is most needed as the approach could more accurately reflect the actual situation on the grid. Meanwhile, the underpinning principle for NTC-based approach is the pre-defined level of maximum commercial exchange capabilities for each border between bidding zones. The characteristics of a particular market largely determine the most effective approach to calculate capacity. In general, the flow-based approach is preferable for markets where capacity among bidding zones is highly interdependent. In contrast, the NTC-based approach is more suitable in less interdependent networks (EC, 2015). However, the suitable method needs to be determined based on the topology and structure of the grid being analysed.

4.3. Spot Market

As real consumption of electricity is not entirely predictable, daily and hourly contracts are needed. Electricity for immediate consumption is traded in a spot market where real-time price is set based on the system operation status, which reflects the needs of congestion or balancing power in the transmission system (Möller et al., 2011). For European countries moving toward an integrated electricity market, the different rules on capacity allocation, congestion management, and trade that exist in Europe need to be harmonised. To harmonise rules and to provide a clear legal framework for efficient capacity allocation and congestion management, ENTSO-E has developed a network code on CACM for capacity allocation, congestion management, cross-border capacity calculation (including day-ahead and intraday market operations, and bidding zones review), and transition into a single electricity market across Europe.

According to the CACM network code, electricity is mainly traded in an intraday market and single day-ahead market through implicit auctions. Intraday market is where market participants are allowed to trade closer to real time and mostly takes place during the day of operation. This market enables market participants to manage risks and respond to changing conditions such as varying wind forecasts. Day-ahead market is where market participants can submit bids and offers to buy or sell energy for delivery the following day. Implicit auction, known as market coupling, is where transmission capacity and electricity are traded together. In an intraday market, the implicit auction is continuous. In a coordinated way, TSOs calculate the available cross-border capacity to allow the implementation of day-ahead and intraday market. To achieve this, TSOs establish a common grid model that incorporates hourly estimation on generation, load, and network status. Using flow-based method, the available capacity is generally calculated and the result becomes one of the key inputs for further calculation process, where all bids and offers in the power exchanges are balanced, taking into consideration the available cross-border capacity in an economically optimal manner (EC, 2015). Thus, power flows from low-price to high-price areas. The market coupling operator (MCO) uses a common algorithm called European Hybrid Electricity Market Integration Algorithm (EUPHEMIA) to optimally match bids and offers. The calculation result is made available to all power exchanges in a non-discriminatory manner. Regarding the calculation results published by MCO, the power exchanges need to inform their clients of the successful bids and offers (PCR, 2016). Accordingly, energy is transferred across the network, a process similar in both single day-ahead and intraday market although the day-ahead market uses single calculation while intraday coupling uses a continuous process throughout the day. Figure 4 illustrates how available capacity is transferred according to the CACM network code.

Figure 4: Electricity Transfer Mechanism According to CACM Network Code

MCO = market coupling operator, TSO = transmission system operator.
Source: Authors.

Capacity calculation for day-ahead and intraday market is coordinated at the regional level to ensure a reliable capacity calculation and to ensure that optimal capacity is available to the market. Therefore, TSOs establish methods for common regional capacity calculation to describe inputs, calculation approach, and validation requirements. This common approach includes a model of the transmission system with the location of generation units and loads relevant to calculating cross-zonal capacity. Information on the available capacity is updated according to the latest data. To calculate cross-border capacity in a coordinated manner, a common grid model for single day-ahead and intraday market purpose is established. This common grid model includes transmission system model with generation units and loads location relevant to calculating cross-border capacity. Timely and accurate information by each TSO is crucial in creating a common grid model. TSOs use a common set of remedial actions, such as redispatching or countertrading, to deal with internal and cross-zonal congestion (EC, 2015). The use of remedial actions in capacity calculation is coordinated by TSOs to facilitate efficient capacity allocation and to avoid unnecessary limitations of cross-border capacities.

Box 1: EUPHEMIA Algorithm

EUPHEMIA is a common algorithm used to allocate cross border capacity on a day-ahead basis and to calculate electricity prices across Europe, with the central objective of maximising overall welfare and increasing transparency in calculating prices and flows. Prior to the application of EUPHEMIA, power exchanges were using several algorithms locally (SESAM, UPPO, SIOM and COSMOS), largely focusing on the features and products of the corresponding power exchanges, and none able to cover the whole set of requirements. In contrast, EUPHEMIA is capable of covering all the requirements and providing solutions within a sensible time frame. EUPHEMIA is a generic algorithm with no limits for the number of markets and network constraints or orders. All orders of the same type submitted by market participants are treated equally. Market participants begin by submitting their orders to the corresponding power exchanges where orders are collected and submitted to EUPHEMIA. The algorithm subsequently decides which orders are to be executed or rejected upon the following considerations:

- The executed orders generate maximum social welfare (consumer and producer surplus plus congestion rent across the regions).
- The executed orders induce power flows that result in net positions within the capacity of the relevant network elements.

Source: PCR, 2016

Due to limited transmission infrastructure, the flow of electricity largely influences the efficiency and functioning of wholesale electricity markets and the operational security of the network. Therefore, congestion management methods and market design arrangements, such as bidding zones configuration, are important to reflect supply and demand distribution. They are crucial foundation for electricity trading, particularly to ensure efficient congestion management and market efficiency. Bidding zones are network areas where market participants can offer energy without having to obtain the transmission capacity to conclude their trade. The idea of clustering some European transmission network nodes into a bidding zone is basically to simplify the physical reality of working the electrical systems for electricity trading. Modification of bidding zone is allowed through splitting, merging, or adjusting the borders (ENTSO-E, 2013). The review process of bidding zones configuration is important to identify structural bottlenecks and to allow more efficient delineation of the zone.

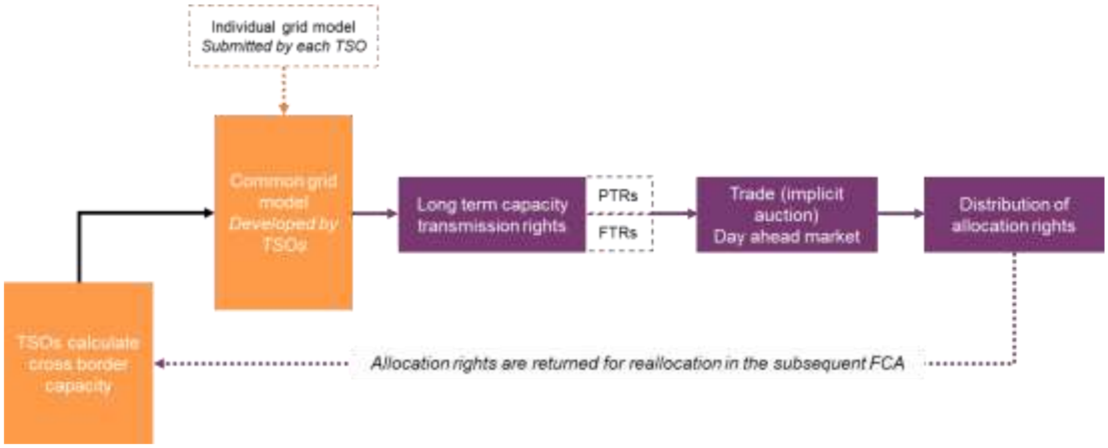
4.4. Derivatives Market (Forward Market)

The inherently non-storable characteristic of electricity makes risk management crucial for all participants in the electricity market, particularly in valuing assets, hedging production, or hedging financial positions. Multiple sets of rules used to regulate the allocation of long-term cross-border transmission capacity among member states across Europe. For that reason, ENTSO-E subsequently developed network codes on FCA to harmonise the existing multiple allocation rules at the European level by formulating a single allocation platform (Mäntysaari, 2015). The main objectives of a single allocation platform are to facilitate long-term transmission rights allocation and the rights transfer between market participants. TSOs must guarantee a transparent and non-discriminatory way to allocate transmission rights by making available all relevant information regarding the auction before the actual auction opens. The allocation of long-term cross border transmission capacity is conducted through explicit auction before the day-ahead time frame. This mechanism consequently allows market participants to mitigate future price risks in their operation area. Explicit auction is where transmission capacity and electricity trading are auctioned separately (ENTSO-E, 2013).

Network codes on FCA set out the calculation, allocation, and pricing mechanism for long-term transmission capacity (Mäntysaari, 2015). TSOs coordinate long-term capacity calculation (years and months ahead) and ensure that calculations are reliable, which, in turn, guarantee that optimal capacity is made available to the market. Accordingly, TSOs develop a common grid model that takes into account all the necessary data for long-term capacity calculation and uncertainties characteristic associated to the long-term time frame (ENTSO-E, 2013). Long-term capacity calculation has two approaches: flow-based approach and coordinated NTC approach. Deciding which approach to use is at the discretion of TSOs. The relevant platform for the allocation of long-term transmission rights to market participants are physical transmission rights (PTRs) relevant to the use-it-or-sell-it principle or financial transmission rights (FTRs) (Mäntysaari, 2015). PTRs allow holders to transmit a specific amount of power between two electricity network nodes in a given time period. In European market, PTR holders have to announce if they are going to exercise their rights before the pre-established deadline (usually the day ahead). In cases where PTR holders failed to declare it, the rights are automatically resold on the short-term market by TSOs on behalf of the holder, also known as UIOSI. FTR hedges the buyer against the market price between two or more price zones (Batlle et al., 2013). FTR allows the holder to receive a financial compensation equal to the positive (if any) market price differential between two areas in a specific time period and direction. These transmission rights are either obligations or contracts and, in both cases, the right holders are settled financially.

Long-term transmission rights are allocated and auctioned to market participants through bids under the single allocation platform. This platform is a point of contract for market participants willing to participate in explicit auctions to require long-term transmission rights (Mäntysaari, 2015). The rights holders are entitled to return their rights for reallocation in a subsequent FCA. Rights holders may receive payment in this situation. Besides that, market participants are allowed to either purchase or transfer long-term transmission rights that are already allocated previously (figure 5). TSOs must be informed and notified about who long-term transmission rights holders would be as they are going to be the counterparties of their respective TSOs (ENTSO-E, 2013). However, network codes on FCA are not designed for very long-term capacity allocation. Ensuring that long-term transmission capacity is reserved for new installation is crucial for risk management and promoting investment in energy generation from renewable sources. As an example, a project of common interest requires significant long-term investment that needs to be supported by a long-term contractual framework (Mäntysaari, 2015).

Figure 5: Electricity Transfer Mechanism According to FCA Network Code



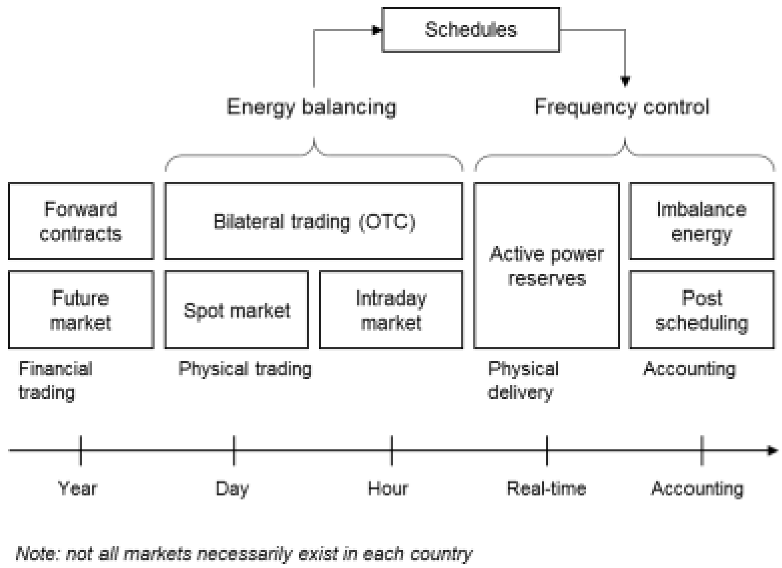
FCA = forward capacity allocation, PTR = physical transmission rights, FTR = financial transmission rights, TSO = transmission system operator.
Source: Authors.

4.5. Grid Balancing and Ancillary Services

Grid Balancing

Electricity balancing is a mechanism that allows TSOs to access a sufficient amount of energy to balance the difference between supply and demand in the transmission systems. Power imbalances lead to deviations in the transmission system, which can cause infrastructure loss, equipment damage, and blackouts. Balancing power deviation is, therefore, crucially important and indicates the level of electricity security of supply (Aikema, 2013). Balance responsible parties (BRPs) and TSOs are assigned to match electricity load and production. BRPs are obliged to maintain the balance of their own generation and consumption portfolio throughout a defined imbalance settlement period. The remaining real-time power imbalance is compensated by TSOs in the respective country. The field responsibilities of BRPs and TSOs are known as energy balancing and frequency control, respectively. The ownership unbundling that stipulates separation of generation and system operation prevents energy suppliers and network operators from acting as a system in parallel. Consequently, they cannot transfer their transmission rights to cross subsidies production by third-party grid usage tariffs or to their production units. This on-going liberalisation makes the ancillary service and energy markets chronologically dependent (Figure 6) (Scherer et al., 2015).

Figure 6: The European Energy Market Model



OTC = over the counter.
Source: Scherer et al., 2015.

As electricity generation and system operation are unbundled, the information associated with production and load is not automatically provided to TSOs. BRPs have to inform respective TSOs about their schedules containing the net energy trade they intend to carry out. TSOs use the sum of overall forecasts provided by BRPs for balancing purpose (Möller et al., 2011). Each consumption schedule has a production schedule and vice versa. It also means BRPs have to pay the imbalance energy, also referred to as 'balancing energy', for the aggregated deviations between scheduled and physical net energy during an imbalance settlement period. Each market trader, utility, generator, and consumer is a part of BRP (Scherer et al., 2015).

Balancing energy is settled at prices set after the real-time balancing in the electricity markets. Broadly, the general settlement schemes in the European electricity market are divided into single and dual price settlement. In a single price scheme, TSO sets a single price for both compensating negative deviations and charging positive in each settlement period. Negative deviation is when there is an oversupply of electricity in the market. Consequently, the price is naturally low during periods with negative deviation. Likewise, the price is high during periods with positive net deviation as the electricity shortage is occurring. This single-price approach provides incentive to deviate in the opposite direction of the net deviation in the control area, e.g. paying during negative deviation periods and receiving payments during positive deviation periods. A strategic position following this incentive will possibly decrease net deviation in much the same way as deploying capacity reserve (Möller et al., 2011). The balancing energy market is also a market for energy transaction in the day-ahead market. It is profitable for BRPs to be in oversupply position on the day-ahead market if the spread between the expecting balancing energy price and the day ahead is negative. Similar thing is true for the positive spread. TSOs set the balancing energy price after the settlement period, to which, in return, the balancing energy market can only offer statistical-arbitrage opportunities. This is when the dual price design emerges to curb such statistical arbitrage opportunities (Scherer et al., 2015). In the dual price settlement scheme, TSO sets a price each for positive deviation and for negative deviation. These prices can also be understood as the single price settlement scheme with an additional general fine imposed for deviation. The dual prices settlement schemes are adopted in most European electricity markets such as France, England, the Netherlands, Spain, and Scandinavia, mainly to encourage BRPs to overlook strategic positions in the balancing energy market (Möller et al., 2011).

Ancillary Services

In addition to energy markets, power grids often have separate ancillary services that provide compensation for actions taken to match the supply and demand for electricity. Power grids use these services to overcome short-term variability in supply and demand and impact of failures in transmission line or power plant (Scherer et al., 2015). Ancillary services are crucial in maintaining security and quality of electricity supply. Frequency and active power control, standing reserve, voltage control, and black start are the four types of ancillary services.

Frequency and active power control ancillary services include primary, secondary, and tertiary reserves. Primary reserve is provided by generation units for system primary control which balance the total energy absorption and total energy generation. They also stabilise frequency within 30 seconds from occurrence of frequency distortion without restoring frequency to its reference level. Activating secondary reserve enables later restoration. Secondary reserve minimises area control error. The range is the interval between minimum and maximum unit active power within 15 minutes from system secondary control activation. Tertiary reserve is activated periodically to restore secondary reserve system when the latter has been reduced as a result of system secondary control operation (Adrianesis et al., 2011).

Standing reserve is the maximum active power quantity that can be made available within 20 minutes to four hours following a related dispatch instruction by TSO.

Voltage control ancillary services maintain voltage within normal operation limits. Dynamic active power reserve and sufficient standing are required for voltage control.

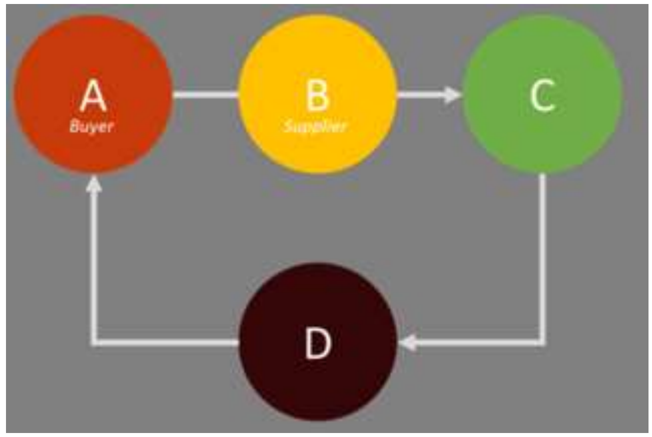
Black start ancillary services are provided by units that inject energy into the system (usually black-start units) following an interruption in a general or partial system without being supported by external supply (Scherer et al., 2015).

4.6. Inter -TSO Compensation Mechanism

Electricity trade also comprises physical transmission, which involves cross-border electricity flow and most probably leads to electrical loses. Therefore, the costs of infrastructure hosting cross-border electricity flows and the cost of electricity losses incurred by national transmission systems that host cross-border flows must be compensated through Inter-TSO Compensation (ITC) mechanism (EC, 2010). Introducing ITC mechanism to the electricity market bans the further use of previous tier system of cross-border tariffs that was destroying all attempts to develop fair cross-border trade. It could, however, increase the tariff burden of domestic grids and significantly reduce TSO income (unless compensated). This mechanism was first implemented in 2002 in nine ITC parties. In early 2004, the total number of ITC parties reached 20 and increased to 32 in late 2009. Currently, ITC mechanism is a voluntary agreement between participating TSOs (Androcec et al., 2011).

Box 2: Electricity Transit Due to Loop Flow

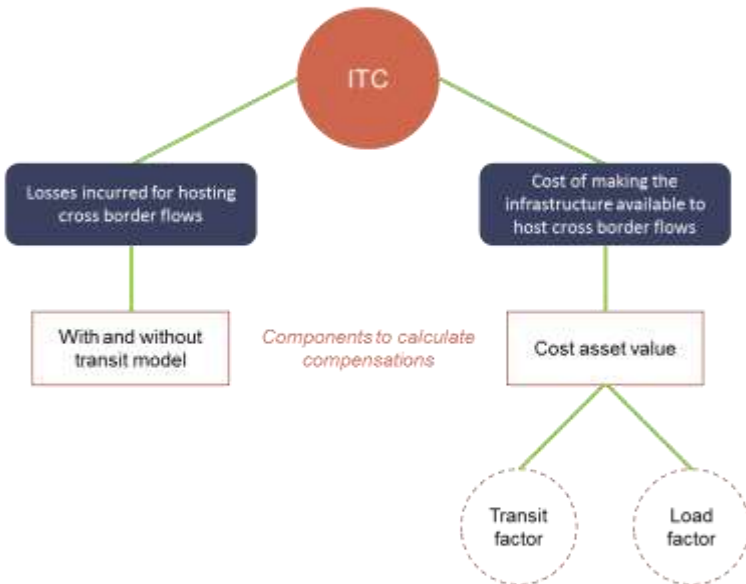
The figure illustrates how power flow can be distributed in disproportion to the trade with several power systems connected. Area A buys power from area B (Q_{AB}). Instead of directly distributing power from B to A, the actual power is flowed from area B through C and D before eventually reaching area A. The part where power flows through C and D is known as loop flow. Attempting to force power exchange flows directly from B to A could possibly result in higher power losses. Loop flows could contribute to network congestions in the affected areas or limit the possibilities of power exchange within or between areas C and D. Loop flow is closely related to power transit. In a situation as illustrated, areas C and D are candidates for compensation for the power transit resulting from the loop flow.



Source: Androrec et al., 2011

Calculating compensation has two main components. First, a transmission losses component based on with-and-without-transit (WWT) model. Here, losses are calculated on each TSO's transmission grid in a load flow situation with and without transits. TSOs would be compensated for costs incurred as a result of hosting cross-border electricity flows on their networks. In addition, operators of national transmission system shall pay the compensation from which cross-border flows originate and the systems where those flows end. Compensations are made on a regular basis with regard to a given time period in the past. If necessary, ex post adjustment of compensation could be made to reflect the actual costs incurred. The magnitude of cross-border flows hosted and cross-border flow designated as originating and/or ending in national transmission systems is determined based on physical electricity flows measured during a given period (EC, 2010). Second, an infrastructure cost component to compensate hosting cross-border flows. The level of infrastructure payment is based on the infrastructure cost asset value being used to host cross-border flows and the amount of cross-border flows between participating TSOs. The cost calculation for hosting cross-border flows is established on the basis of forward-looking long-run average incremental costs that also incorporate investment in new infrastructure, account losses, and an appropriate proportion of the existing infrastructure cost (Androrec et al., 2011). The benefits incurred as a result of hosting cross-border flows is also taken into consideration to reduce compensation payment (Figure 7).

Figure 7: Inter-TSOs Compensation Mechanism



Source: Authors.

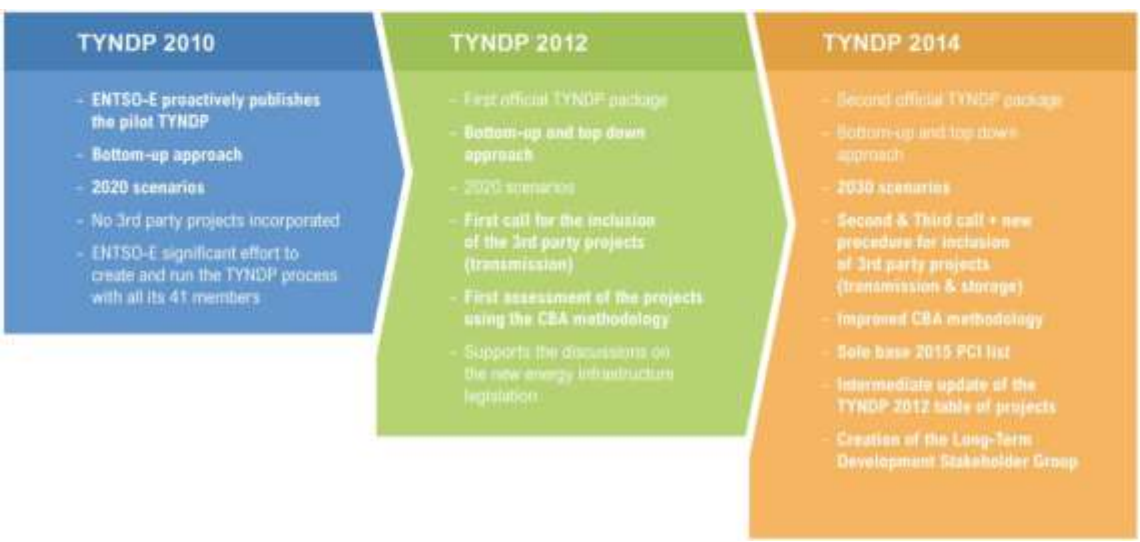
The compensation for losses incurred on the national transmission systems as a result of hosting cross-border electricity flows is calculated separately from compensation for cost of infrastructure hosting cross-border flows of electricity. The sum of annual cross-border infrastructure compensation is distributed among TSOs responsible for national transmission system in proportion to transit factor and load factor. Transit factor refers to transit on the national transmission system as a proportion to the total transits on all national transmission systems. Load factor refers to the square of electricity transits in proportion to load plus transits on a national transmission system relative to the square of electricity transits in proportion to load plus transit for all national transmission systems. According to Commission Regulation (EU) No. 774/2010, the transit factor is weighted 75 percent and load factor is 25 percent (EC, 2010).

An ITC fund comprises costs incurred as a result of transmission losses and infrastructure hosting cross-border flows. ACER estimates the infrastructure value based on forward-looking long-run average incremental costs. ITC fund apportions compensation to participating TSOs based on transits carried by TSOs. Participating TSOs also contribute to the fund according to their net import and export flows. Non-participating countries connected to participating TSOs pay a transmission system for their non-scheduled exports and imports to the networks owned by participating TSOs (EC, 2010). Hosting electricity flows can also be beneficial to the hosting country in terms of congestion rent and improved security of supply (in terms of cost reduction). The latter benefit is the natural advantage of exchange arrangements between TSOs. Countries can either improve supply security within given cost limits or reduce costs and keep security level constant. In practice, it is mostly a combination of both. Other benefits pertain to electricity trade, in terms of payment to power exchange or traders. New investments and network expansions are required to gain more benefits from electricity trading. For this reason, the right incentives mechanism should be available. Increased investment in a highly needed transmission line could increase transit and compensation which, in turn, could pay the line in addition to the local benefit of the line. Nevertheless, Androrec et al. (2011) argue that ITC mechanism does not provide a clear definition of the benefit concept and elements that need to be considered. They further argue that ITC arrangements should incorporate benefits of trade. None of the negotiated methods includes these. Furthermore, the methods do not incorporate the establishment of exchanges and the interaction in trade with a price response. In fact, the less expensive generation resources should be used first in an efficient power system.

5. Ten-Year Network Development Plan

The Ten-Year Network Development Plan (TYNDP) provides a view on electricity infrastructure and potential future investment to achieve a pan-European grid development. Although by itself a non-binding 10-year energy network development plan, it has, through Regulation (EU) 347/2013, established a formal role as the mandated and sole instrument for the selection of projects of common interest (PCIs), including storage projects. ENTSO-E is assigned to develop such a plan, in close collaboration with the European energy regulatory body (ACER), electricity market stakeholders, and ENTSO-G. The methodology applied for the development of this plan is called cost benefit analysis (CBA) on the PCIs. The results are submitted to ACER, the European Commission, and the member states for comments. The plan was first released in 2010 and, as Figure 8 shows, keeps evolving, with expanding contents and methodologies.

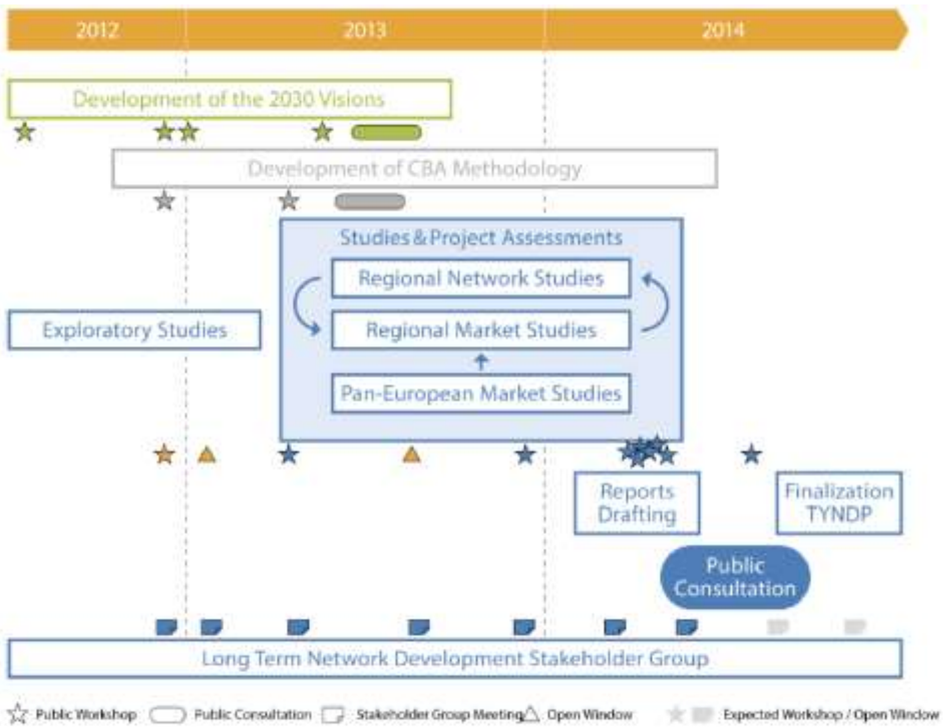
Figure 8: Versions of the Ten-Year Network Development Plan



CBA = cost–benefit analysis, ENTSO-E = European Network of Transmission System Operators for Electricity, PCI = project of common interest.
Source: ENTSO-E, 2014.

Each version of the plan details regional network studies. Figure 9 and Figure 10 show the overall framework and methodology of the plan, respectively.

Figure 9: Process of the Ten-Year Network Development Plan Over the Versions

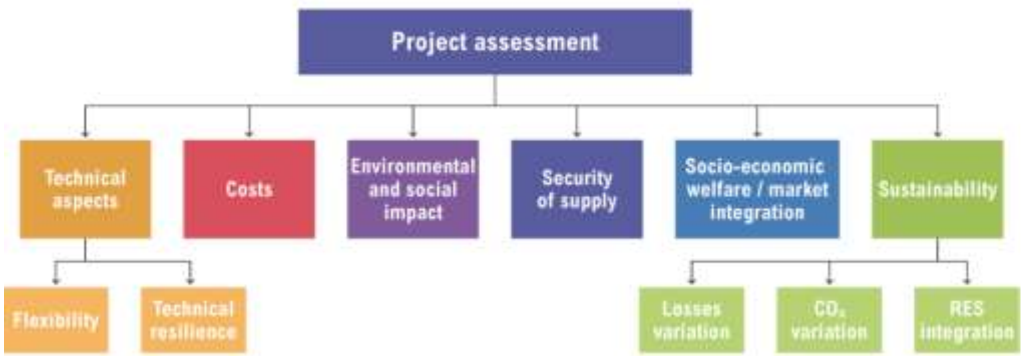


CBA = cost–benefit analysis.
Source: ENTSO-E, 2014.

The Ten-Year Network Development Plan 2016 is the latest version of this development covering six sub-regions of the overall European electricity market. To ensure relevance and high quality inputs from stakeholders, ENTSO-E has formulated a long-term network development stakeholders group which provides valuable inputs on long-term grid development-related issues to build future scenarios for assessment of the value/benefits of PCIs. Importantly, TYNDP not only serves the simple purpose of pan-European grid interconnection and electricity market integration but also serves the strategic purposes of the EU’s move toward clean and green energy as well as carbon emissions reduction targets. TYNDP 2016 proposes the integration up to 60 percent of renewable energy by 2030 through strengthened Europe electricity power grid. This integration aims to achieve cost efficiency and energy security. In the 2016 plan version, all four future scenarios projected up to 2030 assume from 40 percent to 60 percent significant share of renewable energy sources in the total power generation. The plan also balances considerations of energy cost to consumers: affordability and energy security, system reliability, and sustained investment in energy infrastructure.

Figure 10 illustrates the multi-criteria cost and benefit analysis as the assessment methodology built on top of conventional network and market modelling. This methodology was developed by ENTSO-E through public consultation on the 'Guideline for Cost Benefit Analysis of Grid Development Projects'.

Figure 10: Multi-criteria Cost and Benefit Analysis of Grid Development Projects



CO_2 = carbon dioxide, RES = renewable energy sources.
Source: ENTSO-E, 2014.

The Ten-Year Network Development Plan represents an integrated approach of planning for power infrastructure across the borders of the member states. It proposes to develop in the next decade new and upgraded lines equal to 48,000 km that correspond to 120 projects. Around 21,000 km of new lines for alternating current (AC) has been planned. Most of AC technology is planned to be built on new overhead lines, by far the easiest to implement for inland applications. Around 10 percent of the investments are allocated to upgrade existing AC assets. Direct current (DC) is heavily used in Europe recently and around 20,000 km of new high-voltage direct current (HVDC) lines are in the plan, accounting for more than 40 percent of the total additional infrastructure. The growth of new cables is expected to align with the development of new HVDC projects.

Over 75 percent of HVDC lines will be built using cables, with submarine cables representing the greatest length. Almost 5,000 km of HVDC projects are planned onshore and a significant length of HVDC overhead lines is also proposed.

In the coming decades, the major challenge in electricity is to facilitate larger power flows across Europe. The new project is to increase grid transfer capacity (GTC) in main generation areas and consumption areas. GTC has been scaled up from several hundred MW to numerous GW. Another driver for grid investment is refurbishing aging equipment, where the cost associated is crucial for TSOs. Per TYNDP, refurbishment issues appear when grids are upgraded or reconstructed.

Besides estimating the cost and benefits of individual projects, the plan can also indicate their overall impacts on economic, social, and environmental welfare. Through integrated planning, the use of resources and infrastructure from different member states could be optimised to maximise absorption of intermittent renewable energy such as solar PV and wind power.

Through such planning, TYNDP is able to identify potential system development issues in the future, such as bottlenecks in infrastructure capacity. Although total consumption of electricity is not likely to surge fast or significantly, the need to develop large amount of intermittent renewables increases the demand for capacity to transport large amount of power across borders. These bottlenecks call for additional cross-border transmission capacities and implementation of appropriate technologies to reinforce the pan-European grid. TYNDP is thus very informative regarding the kind of technologies that could best address bottleneck issues.

TYNDP's development process typically involves intensive consultation with stakeholders from all member states on their needs and concerns over all sorts of practical challenges and barriers in grid interconnection and market integration. It is through such process that interconnection and integration become guaranteed as mutually beneficial and where understanding of common interests in the endeavour could be built. Thus, more than planning, TYNDP is, in many senses, also communication and balancing. In this way, TYNDP is a very effective implementation tool in energy policies, policy targets and investment, operation, and other actions by all stakeholders.

6. Lessons and Challenges for ASEAN

Lessons

As countries in ASEAN are becoming larger energy consumers and growing participants in the global energy markets, governments will be increasingly confronted by challenges similar to those faced by European member states. Liberalisation of electricity market promises to become an elevated priority since ASEAN needs to ensure that energy supplies are accessible and affordable to support its rapid economic growth and development. Interconnecting energy generation to renewable energy sources is also set to become a major imperative, particularly in the context of the region's fast-rising energy demand, growing urban population, and the expanding role of fossil fuel-based energy. It is widely acknowledged that engagement among countries in ASEAN is increasingly important to address these common energy challenges. Europe's experience on establishing integrated electricity market provides approaches that could be learned as precedents in establishing integrated electricity market in ASEAN.

- ASEAN will need a target model as top-level design of electricity market for ASEAN power grid interconnection or for ASEAN electricity market integration. Since the 1990s, ASEAN has made efforts to link its electricity grids and gas pipelines across countries in the region. The two flagship projects for such infrastructure integration are the ASEAN Power Grid (APG) and the Trans-ASEAN Gas Pipeline (TAPG). Although greater cooperation has been achieved and infrastructure development is progressing well, the grid has not operated yet on a multilateral level. Based on the experience of establishing APG and TAPG, a stepwise approach for power grid interconnection would be preferable rather than taking a big bang where everything is strived for simultaneously.
- The ASEAN region requires developing a common vision on the future needs of power infrastructure (including both power transmission and power-generation assets) and translate it into an integrated development plan which serves as an important basis for interconnecting energy infrastructure across countries to

achieve an ASEAN-wide grid development. The infrastructure investment should be coordinated to minimise costs while meeting certain well-articulated ASEAN energy policy targets, including renewable energy share and carbon emissions reduction. The on-going development of ASEAN Energy Market Integration Blueprint and Roadmap can become an important base to accommodate this prerequisite.

- Electricity is often the most restricted energy product in ASEAN and thus market integration is largely affected by national energy market regulations and segmented by international boundaries. Considering that each power grid is unique and governed by its own policies and codes, ASEAN needs to develop common principles, rules, standards, and network codes that govern grid operation and electricity trade, such as TSOs; utilities and other stakeholders in the national electricity market; regulatory authority; and role of national regulatory authorities, agreements, and licences.
- Establishing an open and competitive electricity market requires transparent market rules and principles that allow new investors to enter the market. Transparent rules and principles could also provide a strong legal protection; enhance investor confidence; reduce transaction costs; and enable the free flow of goods, services, and capital. Many studies argue that enhancing competitiveness in electricity market often requires unbundling vertically integrated energy enterprises. In many ASEAN countries, state-owned electricity companies are usually dominant players and given preferential treatment. Hence, this provides little room for new market players to enter the market. In fact, bilateral and multilateral contracts can still co-exist alongside regional instruments. Currently, independent transmission companies are participating in the regional market along with traditionally vertically integrated companies. The different degrees of electricity market reform will not hamper the development of regional market as long as countries are paving the way to transition into more transparent market.
- Another precondition for an integrated electricity market is the adoption of a market-oriented pricing mechanism. Such mechanism requires a dynamic price-setting algorithm that aims to set out price that balances supply and demand in the electricity market. The main advantage of this algorithm is its enhancement of efficiency where electricity is delivered at the most cost-effective prices that maximise benefits for both producers and consumers. Currently, in most ASEAN countries, electricity tariff is still regulated and stipulated by the government.

Challenges

- The effectiveness of integration largely depends on efficient coordination between national energy markets. Electricity market integration is highly characterised by a long and diversified process as well as power transfer. The larger member countries that are against sovereignty delegation in energy security policy mainly hamper the power transfer given to the ASEAN level. The fundamental reason is they are in fact seeking maximum protection for their interests amid the market opening and restructuring process. The reluctance to transfer such power is also partly related with differences within ASEAN countries in terms of technological, ownership, social capital, and legal heritage. The unbalance interests and unequal efforts will make the entire market less competitive and vulnerable to shocks. Political barriers—including lack of political trust—in coordination among member countries might also be a practical concern. Mutual distrust among trading partners in ASEAN is an additional factor that will slow down the phase of integrating electricity market.
- Energy strategies to achieve energy supply security in individual countries are often described as strategies to meet domestic demand through national efforts and reduced dependency on other countries. This perspective limits opportunities for energy trade and regional cooperation mechanism. There has to be a shift in paradigm from pursuing energy security through own efforts to regional cooperation. When individual countries are pursuing regional cooperation mechanism to secure their energy supply, more investment come that, in turn, contribute to optimisation of available energy resources throughout the region.
- Integrated electricity market has an enormous potential that can be realised at reasonable costs. However, price distortions from existing fossil fuel subsidies in many ASEAN countries and unequal tax burdens for renewable energy sources lead to the failure of market in valuing the social benefits of renewable energy sources. The IEA report suggests that to a certain extent (on the basis of LCOE), many renewable technologies are cost competitive compared with conventional sources and even without subsidies for their generation (IEA, 2014). However, subsidies can create artificially lower cost of fossil fuel relative to renewables that further discourage the use of renewable energy sources. Removal of fossil fuel subsidies is, therefore, central in establishing a non-discriminative market and transparent price mechanism.
- Integrated electricity market is an effective tool to achieve the ASEAN energy policy targets to increase renewable energy share and reduce carbon emissions. However, most ASEAN countries are still highly dependent on fossil-fuel-based energy to meet the rapid energy demand due to their economic and demographic growth. Therefore, the energy policy targets are still far from being attained at

least until 2020. Another challenge in increasing renewable energy share is lack of access to finance, knowledge, and technologies to develop the renewables potential. Deployment of renewable technologies is still deterred by intellectual property rights issues.

Conclusion

ASEAN member countries are becoming larger energy consumers and growing participants in the global energy market. Therefore, governments are increasingly confronted by challenges similar to those faced by European countries. Electricity liberalisation promises to become a top priority considering that ASEAN needs to ensure security in energy supply to support its development. Moreover, under the liberalised electricity market arrangement, renewable energy sources could be made more affordable, accessible, and locally sourced.

First and foremost, ASEAN will need a target model as the top-level design of the electricity market for ASEAN power grid interconnection. Second, the region needs to develop a common vision regarding the future needs of power infrastructure that translates into an integrated plan, which serves as an important basis for interconnecting cross-border energy infrastructure. Third, ASEAN needs to formulate common principles, rules, standards, and network codes that govern grid operation and electricity trade. Fourth, the region has to ensure that new investors are allowed to enter the market. The last precondition for an integrated electricity market is the adoption of a market-oriented pricing mechanism.

Some challenges for market integration perceived by ASEAN include dependency on the fossil fuel-based energy and lack of political trust in coordination among member countries. Electricity market integration is also highly characterised by a long and diversified process that generates high risks. Individual countries in ASEAN tend to achieve their energy supply security through domestic efforts and reduced dependency on other countries. This paradigm often limits the opportunity to expand energy trade to regional level. Another notable challenge is price distortions from existing fossil fuel subsidies in many ASEAN countries exacerbated by unequal tax burdens for renewable energy sources.

References

Aikema, D., R. Simmonds, and H. Zareipour (2013), 'Delivering ancillary services with data centres', *Sustainable Computing: Informatics and Systems,* vol.3, no.3,pp.172–182.

Andrianesis, P., P. Biskas, and G. Liberopoulos (2011), 'An overview of Greece's wholesale electricity market with emphasis on ancillary services', *Electric Power Systems Research,* vol. 81, no. 8, pp.1631–1642.

Androcec, I., S. Krajcar, and I. Wangensteen (2011), 'Optimization of costs and benefits in Inter TSO Compensation mechanism', p.647.

Batlle, C., P. Mastropietro, and R. Gómez-Elvira (2014), 'Toward a Fuller Integration of the EU Electricity Market: Physical or Financial Transmission Rights?', *The Electricity Journal,* vol.27, no.1, p.8.

Bekaert, D., L. Meeus, D. Van Hertem, E. Delarue, B. Delvaux, G. Kupper, R. Belmans, W. D'Haeseleer, K. Deketelaere, and S. Proost (2009), 'How to increase cross border transmission capacity? A case study: Belgium', pp.1.

Böckers, V, J. Haucap, and U. Heimeshoff (2013), Benefits of an integrated European electricity market: the role of competition (Research paper), European Union. Available at: http://www.europarl.europa.eu/committees/en/supporting-analyses-search.html (accessed 7 February 2016).

Cavaliere, A., V. Giust, and M. Maggi (2013), 'Efficient mechanisms for access to storage when competition in gas markets is imperfect', *Energy Economics,* vol.36, p.481.

Ding, Y., S. Pineda, P. Nyeng, J. Ostergaard, E.M. Larsen, and Q. Wu (2013), 'Real-Time Market Concept Architecture for EcoGrid EU-A Prototype for European Smart Grids', *IEEE Transactions on Smart Grid,* vol.4, no.4, pp.2006–2016.

European Commission (EC) (2016), 'Market Legislation', European Commission, Available at: https://ec.europa.eu/energy/en/topics/markets-and-consumers/market-legislation (accessed 8 February 2016).

European Commission (EC) (2015), Commission Regulation (EU) 2015/1222: Establishing a guideline on capacity allocation and congestion management, Available at: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32015R1222&from=EN (accessed 6 February 2016).

European Commission (EC) (2010), on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging, Available at: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32010R0774&from=EN (accessed 8 February 2016).

ENTSO-E (2016), 'Latest Updates & Milestones', European Network of Transmission System Operators, Available at: https://www.entsoe.eu/major-projects/network-code-development/updates-milestones/Pages/default.aspx (accessed 10 February 2016).

ENTSO-E (2014), 'Ten Year Network Development Plan 2014', Available at: https://www.entsoe.eu/major-projects/ten-year-network-development-plan/tyndp-2014/Documents/TYNDP%202014_FINAL.pdf (accessed 6 February 2016).

ENTSO-E (2013), Network Code on Forward Capacity Allocation, Available at: https://www.entsoe.eu/fileadmin/user_upload/_library/resources/FCA_NC/131001_-_NC_FCA_final.pdf (accessed 8 February 2016).

Hopenhayn, H.A. (1992), 'Entry, Exit, and Firm Dynamics in Long Run Equilibrium', *Econometrica*, vol. 60, no. 5, pp.1127-1150.

International Energy Agency (IEA) (2014), Key world energy statistics. Paris: IEA. Available at: http://www.iea.org/publications/freepublications/publication/KeyWorld2014.pdf (accessed 7 February 2016).

The Institute of International and European Affairs (IIEA) (2014), Regional Electricity Markets – Seven Steps to a Single European Electricity Market, Available at: http://www.iiea.com/blogosphere/regional-electricity-markets--seven-steps-to-a-single-european-electricity-market (accessed 7 February 2016).

Imran, K. and I. Kockar (2014), 'A technical comparison of wholesale electricity markets in North America and Europe', *Electric Power Systems Research*, vol. 108, pp.59–67.

Jamasb, T. and M. Pollitt (2005), 'Electricity Market Reform in the European Union: Review of Progress Toward Liberalization & Integration', *The Energy Journal*, vol. 26, no. 1, pp.11–41.

Mäntysaari (2015), *EU Electricity Trade Law: The Legal Tools of Electricity Producers in the Internal Electricity Market*. Switzerland: Springer International Publishing.

Möller, C., S.T. Rachev, and F.J. Fabozzi (2011), 'Balancing energy strategies in electricity portfolio management', *Energy Economics*, vol. 33, no. 1, pp.2–11.

Price Coupling of Regions (PCR) (2016), EUPHEMIA Public Description: PCR Market Coupling Algorithm, Available at: https://www.nordpoolspot.com/globalassets/download-center/pcr/euphemia-public-documentation.pdf (accessed 6 February 2016).

Pidlisna, Y. (2014), ‘Opportunities and Challenges for Interconnection Investment in Europe: Case Example of Estlink HVDC Power Cable between Estonia and Finland’, International Association for Energy Economics.

Ruska, M. and L. Similä (2011), ‘Electricity markets in Europe: business environment for smart grids’, VTT Tiedotteita, Available at: http://www.vtt.fi/inf/pdf/tiedotteet/2011/T2590.pdf (accessed 7 February 2016).

Scherer, M., M. Zima and G. Andersson (2013), ‘An integrated pan-European ancillary services market for frequency control", *Energy Policy*, vol. 62, pp.292–300.

ERIA Discussion Paper Series

No.	Author(s)	Title	Year
2016-26	Tsani Fauziah RAKHMAH and Yanfei LI	A review on Institutional Framework, Principles, and Key Elements for Integrated Electricity Market: Implications for ASEAN	Oct 2016
2016-25	Ayako OBASHI	Optimal Trade Policy and Production Location	Sep 2016
2016-24	Kazunobu HAYAKAWA, Nuttawut LAKSANAPANYAKUL, Hiroshi MUKUNOKI and Shujiro URATA	Impact of Free Trade Agreement Utilisation on Import Prices	Aug 2016
2016-23	Lili Yan ING, Olivier CADOT and Janine WALZ	Transparency in Non-tariff Meausres: An International Comparison	Aug 2016
2016-22	VO Tri Thanh and Cuong Van NGUYEN	Towards Responsive Regulatory Management Systems: Country Report for Viet Nam	July 2016
2016-21	Gilberto M. LLANTO	Towards a Requisite Regulatory Management System: Philippines	June 2016
2016-20	Lili Yan ING and Olivier CADOT	Facilitating ASEAN Trade in Goods	June 2016
2016-19	Doan Thi Thanh HA, Kozo KIYOTA, and Kenta YAMANOUCHI	Misallocation and Productivity: The Case of Vietnamese Manufacturing	May 2016
2016-18	Vangimalla R. REDDY, Shardendu K. SINGH and Venkatachalam ANBUMOZHI	Food Supply Chain Disruption due to Natural Disasters: Entities, Risks, and Strategies for Resilience	May 2016

No.	Author(s)	Title	Year
2016-17	Arindam DAS-GUPTA, Gemma B. ESTRADA, Donghyun PARK	Measuring Tax Administration Effectiveness and its Impact on Tax Revenue	Apr 2016
2016-16	Naohiro YASHIRO	Regulatory Coherence: The Case of Japan	Mar 2016
2016-15	Song June KIM and Dae Yong CHOI	Regulatory Coherence: The Case of the Republic of Korea	Mar 2016
2016-14	Peter CARROLL, Gregory BOUNDS and Rex DEIGHTON-SMITH	Towards Responsive Regulations and Regulatory Coherence in ASEAN and East Asia: The Case of Australia	Mar 2016
2016-13	Derek GILL	Defining Regulatory Management System	Mar 2016
2016-12	Derek GILL	Regulatory Coherence: The Case of New Zealand	Mar 2016
2016-11	Sang-Hyop LEE, Jungsuk KIM and Donghyun PARK	Demographic Change and Fiscal Sustainability in Asia	Mar 2016
2016-10	Ayako OBASHI and Fukunari KIMURA	The Role of China, Japan, and Korea in Machinery Production Networks	Mar 2016
2016-09	Ayako OBASHI and Fukunari KIMURA	Deepening and Widening Production Networks in ASEAN	Mar 2016
2016-08	Willem THORBECKE	Increasing the Resilience of Asian Supply Chains to Natural Disasters: The Role of the Financial Sector	Feb 2016

No.	Author(s)	Title	Year
2016-07	Hiroyuki NAKATA, Yasuyuki SAWADA and Kunio SEKIGUCHI	Market Concentration and Risk-Prevention Incentives: The Case of the Hard Disk Drive Industry	Feb 2016
2016-06	Meinhard BREILING	Tourism Supply Chains and Natural Disasters: The Vulnerability Challenge and Business Continuity Models for ASEAN Countries	Feb 2016
2016-05	Masaru TANAKA and Shigeatsu HATAKEYAMA	Towards Reframing the Spirit of ASEAN Environmentalism: Insights from Japan's COHHO Experience and Studies	Feb 2016
2016-04	Manaek SM PASARIBU	Challenges of Indonesian Competition Law and Some Suggestions for Improvement	Jan 2016
2016-03	VO Tri Thanh and NGUYEN Anh Duong	Promoting Rural Development, Employment, and Inclusive Growth in ASEAN	Jan 2016
2016-02	Venkatachalam ANBUMOZHI	Convergence of Opportunities: Resilience and the ASEAN Community	Jan 2016
2016-01	Lili Yan ING, Shujiro URATA and Yoshifumi FUKUNAGA	How Do Exports and Imports Affect the Use of Free Trade Agreements? Firm-level Survey Evidence from Southeast Asia	Jan 2016

Previous year of ERIA Discussion Paper, can be downloaded at:

http://www.eria.org/publications/discussion_papers/FY2015/
http://www.eria.org/publications/discussion_papers/FY2014/
http://www.eria.org/publications/discussion_papers/FY2013/
http://www.eria.org/publications/discussion_papers/FY2012/
http://www.eria.org/publications/discussion_papers/FY2011/
http://www.eria.org/publications/discussion_papers/FY2010/
http://www.eria.org/publications/discussion_papers/FY2009/
http://www.eria.org/publications/discussion_papers/FY2008/