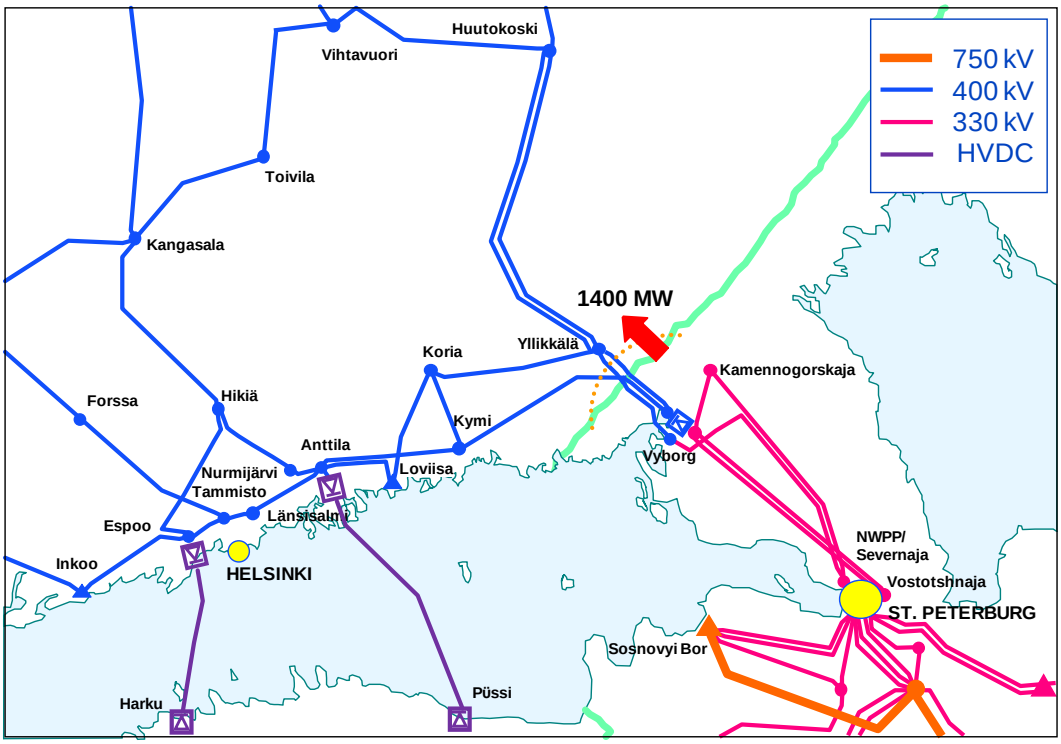
Open your mind. LUT.
Lappeenranta University of Technology

Final Report 20/12/2013

Cross-border electricity trade between the Nordic 'energy-only' market and the Russian capacity-based market



Lappeenrannan teknillinen yliopisto
Lappeenranta University of Technology

LUT Energy **www.lut.fi**
Department of Electrical Engineering

P.O. Box 20
FI-53851 Lappeenranta
FINLAND

Preface

This report presents the results obtained in a research project carried out at Lappeenranta University of Technology and financed by Fingrid Oyj. The project was carried out between November 2012 and November 2013. The focus of the research project was on the development of Russian electricity market, and the electricity cross-border trade between the Nordic and Russian markets.

This report provides an overview of the electricity market design and price drivers in the Russian electricity market. In addition, the report discusses the challenges that results from the differences in the market designs in the 'energy-only' Nordic and the capacity-based Russian markets. The differences in the market designs have recently led to inefficient use the interconnector capacity between the two markets.

Satu Viljainen, Mari Makkonen, Olga Gore, Dmitry Kuleshov, Evgeniia Vasileva

Table of contents

Preface 1
Table of contents 2
Acronyms 3
Abstract 4
1. Introduction 5
2. Electricity and capacity markets in Russia 6
2.1 Electricity market 6
2.1.1 Day-ahead market 6
2.1.2 Balancing market 8
2.2 Capacity market 10
2.2.1 Contracts for new generation 11
2.2.2 Competitive Capacity Auctions 12
2.2.3 Generators' obligations 15
2.2.4 Demand side's capacity cost 15
2.2.5 Imports and exports in capacity market 16
2.3 Price drivers 16
2.3.1 New investments 17
2.3.2 Retirement of old generation 18
2.3.3 Demand increase 19
2.3.4 North West zone of free power flow 20
2.3.5 Price modelling 21
3. Electricity trade between the Nordic and the Russian markets 23
3.1 Modelling cross-border trade 23
3.1.1 Two-market-model 24
3.1.2 Trade arrangements 26
3.1.3 Results 28
3.1.4 Welfare analysis 32
3.2 Possibilities of explicit auction 33
4. Discussion 36
4.1 Prospects of Nordic-Russian cross-border trade 36
4.2 Other markets 36
4.2.1 PJM-MISO 36
4.2.2 UK-Ireland 37
4.3 Lessons for Europe 37
5. Conclusions 39
6. References 41

Acronyms

ATS	Administrator of Trading System
BETTA	British Electricity Trading and Transmission Arrangements
CCA	Competitive Capacity Auction
CDA	Capacity Delivery Agreements
CPM	Capacity Payment Mechanism
EWIC	East-West Interconnection
FAS	Federal Antimonopoly Service
LMP	Locational Marginal Pricing
LNG	Liquefied Natural Gas
LTA	Long-Term Agreements
MED	Ministry of Economic Development
PJM	Pennsylvania-New Jersey-Maryland Interconnection
SO	System Operator
TGK	Territorial Generating Company
TSO	Transmission System Operator
UK	United Kingdom
WGK	Wholesale Generating Company

Abstract

This report discusses the challenges of cross-border trade between two electricity markets that have distinctively different market designs, namely the Nordic 'energy-only' market with zonal pricing and the capacity-based Russian market with nodal pricing. The results presented in this report are based on empirical and theoretical analysis concerning the use of the interconnector between the Nordic and Russia markets under different kinds of cross-border trade arrangements. The current institutional setting classifies as a monopolistic use of the interconnector. Market coupling with the cross-border flow determined on the basis of the electricity price difference between the two markets would increase welfare in both markets. However, so long as subsidies (e.g. capacity payments for firm electricity generation) are paid on one side of the market and not on the other, the trade across the border may be complicated by politically difficult distributional effects.

Market designs across the border are not the only thing affecting the trade but the price difference between the two markets is what creates incentives for trade in the first place. Uncertainties at present exist in what will be the shares of capacity and electricity in the total costs of electricity in Russia. The amount of new generation entering the market under centrally planned mandatory investment program is the primary driver of the capacity cost development. In terms of electricity costs, similar role can be assigned to the price of domestic gas. For example, if the domestic gas price is increased in accordance with the official plans (i.e. annually by 15% on average during next few years), the day-ahead electricity prices will increase significantly because of the importance of gas in electricity generation. Our modelling results indicate that by 2016, the gas price increases alone could increase the electricity prices as much as 10-15€/MWh in the North-West Russia where gas-fired power plants constitute almost 65% of the total installed electricity generation capacity. The question of domestic gas price is essentially a political one.

Our analysis shows that the possible short-term consequences of having an energy-only market on one side and a capacity-based market on the other side include the inefficient use of the interconnector capacities and inverse flows between the two markets. In the long-term, the problem of asymmetric investment conditions emerges. Market coupling is a feasible way to organize the cross-border trade even when the market designs differ. However, the existence of unilateral subsidy schemes, whether related to the renewable energy supply (RES) or the firm electricity generation, may give raise to concerns about the distributional effects that are political in nature.

1. Introduction

Over the past two decades, the electricity markets have been restructured all around the world. The key target has been to liberalize markets to increase competition. Most reforms include privatization of generation assets, as well as the vertical separation and horizontal restructuring. However, the solutions to congestions management are more diverse. In principle, two basic congestion management methods exist: the zonal and nodal pricing. In a fairly non-congested network, zonal pricing is possible where as a highly congested meshed network often requires nodal pricing. Another respect in which the electricity markets differ is how the electricity generation capacity is remunerated. (Littlechild, 2006). In an 'energy-only' market, electricity generators earn money only when produce electricity where as in the capacity-based markets the generators' have two separate revenue streams: they earn money when they produce, and for being available to produce.

Nordic electricity market is a zonal energy-only market where as the Russian market is a nodal capacity-based market. Zonal pricing is generally used in Europe. In zonal markets, the power exchanges carry out the price calculation and transmission system operators (TSOs) inform the exchanges about the available interconnector capacities between the zones. The number of zones is usually quite small; for example, there can be only one price zone within the country or, depending on the grid congestion, few price zones. The zonal markets are typically characterized as energy-only markets, which mean that the market of electric energy alone is expected to ensure the revenue adequacy for electricity generators. The objective is free price formation without price regulation.

Nodal pricing or locational marginal pricing (LMP) refers to a centrally dispatched electricity market, where the system operator (SO) is responsible for the optimal use of the electricity system, including the optimal dispatching of the power plants and the efficient use of the transmission networks. In a centrally dispatched system, a node is defined as the entry or exit point of the main grid, and the nodal prices encompass the price of energy, losses and congestion fees at a specific location of the electricity system. Usually, there are thousands of nodes in the electricity markets depending on the geographic area of the markets and typography of the grid. Nodal pricing is often applied in markets that are characterized by congested transmission networks. Network constraints may give rise to market power problems that are often dealt with by introducing price caps. However, such price caps prevent the generators from recovering their total costs. Hence, separate capacity remunerations are often used to overcome the revenues inadequacy problem caused by the price caps. Capacity mechanisms include, for example, capacity payments, capacity obligations, capacity auctions, and reliability options.

This report focuses on the cross-border trade between these two markets that have distinctively different market designs. The results presented in this report are mainly based on empirical analysis of how the current market rules affect the use of the interconnector between the Nordic and Russian market, and how certain adjustments of the rules could change the situation.

2. Electricity and capacity markets in Russia

Over the past decade the Russian electricity industry has undergone the major reform that has aimed to increase the efficiency of the energy companies in Russia and attract private investments into the power sector. The reform process, accompanied by reorganization of the energy monopoly "RAO UES of Russia", privatization of generation and sale companies and the electricity and capacity trade liberalization was completed in 2011. The outcomes of the reform include the wholesale markets of electricity accessible to both independent power producers and large electricity end-users and the capacity market available only to power producers.

The rationale for the capacity market introduction in Russia is similar to the reasons found in some electricity markets of the USA that is to compensate existing and new generation resources for their fixed, going-forward costs that are not covered by operating in the electricity market (PJM, 2009). In accordance with the initial plans of regulators, competition among generators on electricity and capacity markets was considered as the main instrument for achieving the fundamental targets of the power sector reform such as ensuring reliable and cost-efficient operation of the power sector in both short and long-term perspectives. In addition, it was expected that the wholesale electricity and capacity markets with free prices determined by the interplay of supply and demand would increase the investment attractiveness of the power sector (Ministry of Industry and Energy, 2010). However, in an effort to accelerate and at the same time implement control over investments in construction of new and modernization of existing generation resources the government has launched a massive ten-year investment program in the power generation sector. At the end of 2010, the generation companies of Russia entered into the government contracts for construction of new capacities which guarantee the owners of new power plants accelerated reimbursement of a major share of their investments though the individual regulated rates in the capacity market.

2.1 Electricity market

The Russian electricity market consists of the day-ahead market and the balancing market. The day-ahead market is the central place for electricity trade in Russia. In 2011, a total of 213 buyers and 51 producers of electricity were registered as participants of the day-ahead market. The total amount of electricity traded in the day-ahead market was 864,9 million MWh which constitutes approximately 80 % of all electricity volumes traded in the wholesale market in 2011. The total market turnover was around 18,4 billion Euros.

2.1.1 Day-ahead market

The day-ahead market model in Russia employs the concept of bid-based, security constrained economic dispatch with nodal prices. Usually, nodal pricing is used in the markets where high transmission losses and insufficiency of transmission capacity between regional power systems make application of uniform price auctions economically unacceptable. Electricity prices are defined for each location of the grid and include the costs of marginal energy, marginal losses and transmission congestions.

The Commercial Operator "ATS" (or power exchange) supervises operation of the day-ahead market of Russia in close cooperation with the System Operator (SO). The computation model used by the SO and ATS to evaluate day-ahead market prices includes around 8100 nodes, 12600 power lines and 900 groups of generation units. The market operates without price caps and the Federal Antimonopoly Service of Russia (FAS) monitors the day-ahead market for the purpose of market power detection.

Prior to the beginning of the day-ahead market auctions, the ATS and SO carry out the procedure of unit commitment. The objective is to define the optimal set of generators to meet the expected demand over a future week horizon at minimal total cost of production and also to reduce the number power units' start-ups and shutdowns over the given time period. The time horizon for which optimal turn-on and turn-off schedules of generation units are determined is one full week that begins on Saturday. Not later than four days before the period starts, producers must send notifications to the SO about each generation unit's state, its technical parameters and declared generation schedule at each hour of the concerned period. At approximately the same time, the Commercial Operator ATS receives price offers submitted by producers for the purpose of participation in the unit commitment procedure. The offer should contain production plans and maximal prices of electricity production for every generation unit of a producer at each hour of the prescribed one-week period. In addition, the producers inform the ATS of start-up cost of their generation units. The ATS then transfers the collected data to the SO which, in turn, based on own forecast of hourly demand within the territories of Russia, solves the unit commitment problem taking into account technical constraints of the power system. The nuclear, hydro power plants and must-run thermal generators, however, should operate regardless of market prices and they are excluded from the procedure of unit commitment. Therefore, the solution defines a proper set of remaining thermal generators to produce for the period initially from Saturday to Tuesday. On Monday the SO updates results of unit commitment solution for the last three days of the prescribed one-week period. In accordance with the market rules, only those producers whose generation units were selected to produce in unit commitment are allowed to participate in the day-ahead market. The committed generators cannot be excluded from the day-ahead market auctions. Therefore, in order to prevent possible abuse of market power, the prices submitted by generators to the unit commitment procedure are later utilized by the commercial operator as "price caps" for the bids submitted by these generators to the day-ahead market.

Trading in the day-market is organized as a closed auction with one trading cycle per day. Five hours before the day-ahead market gate-closure at latest, buyers must declare to the SO their maximal planned consumption at each hour of the following day of actual delivery. Based on this information and results of unit commitment, the SO defines the operational constraints of the available generators and transmission resources for each hour of the following day. The data is then transferred to the ATS which, in turn, collects supply and demand bids from the market participants for the day-ahead market auction. After the gate-closure of the day-ahead market at 13:30 (Moscow time), the ATS holds a competitive auction of participants' offers. As a result of the auction the ATS defines trade schedules of the market participants and estimates prices of electricity at each location of the system. The results are published at 17:30 (Moscow time). The nodal prices are obtained for each hour of the following day, taking into account the operational constraints of the power system determined by the System Operator. In the day-ahead market the power producers also get one-time payments for planned start-ups of their generation units prescribed by the unit commitment

solution. In order to collect necessary amount of money to cover start-up costs of the assigned generators, the commercial operator increases financial obligations of buyers in the day-ahead market based on the data on the variations of their monthly consumption.

2.1.2 Balancing market

The balancing market of electricity in Russia is an aftermarket to the day-ahead market. It is a real-time market organized by the System Operator (SO) of Russia with the main objective of minimizing the costs of deviations of actual electricity consumption and production from the planned day-ahead market trade schedule. The auctions of participants' offers in the balancing market are held by the SO twelve times during the day of actual delivery of electricity. In the balancing market auctions, the SO utilizes the same concept of bid-based, security constrained economic dispatch with nodal prices which is employed in the day-ahead electricity market of Russia. The nodal prices obtained in result of optimization in the balancing market auctions are called "indicators of balancing market" (later referred to as BM price in Table 1). Similar to the day-ahead market's nodal prices they also include the marginal costs of energy, losses and transmission congestions.

Price offers of market participants

As opposed to the day-ahead market auctions in which customers are allowed to make their price bids, the short-term electricity demand in the balancing market is forecasted by the SO, and customers with non-dispatchable load are not allowed to bid into the auctions. In addition, the bids of generators that they have posted earlier to the day-ahead market are utilized by the SO for the second time in the balancing market auctions. Nevertheless, producers and customers with regulated consumption have a right to modify their price offers by sending to the SO "quick" price taking offers for change of their production and consumption amounts. The offers must be submitted to the SO at the latest 90 minutes before the next balancing market auction takes place. When submitting a price taking offer, a producer must specify the amount of electricity to which he is willing to increase or decrease his production irrespective of prices that will be formed in the balancing market auction. Similarly, a customer with regulated consumption must specify the amounts to which he is willing to increase or decrease his consumption irrespective of the future auctions prices. The modified offers are then utilized by the SO to establish optimal production schedule of generators sufficient to meet the forecasted demand over a next two hours horizon.

The generators that are rejected during the unit commitment procedure can be later selected in the balancing market if there is a need for their participation in the real-time power dispatch. In accordance with the market regulations, inoperative generators can optionally submit their day-ahead market price offers to the commercial operator. These offers, however, must contain additional information about the start-up costs of the respective generation units. The offers of the switched off generators are not taken into account during the day-ahead market auction but they are transferred by the commercial operator to the SO, which can later utilize them in the balancing market auctions.

Deviations and price settlement in the balancing market

The real production and consumption schedules always differ from those obtained in the day-ahead market. In compliance with the market rules, all deviations between planned and actual trade schedules at nodes can be attributed to internal and external initiatives of market participants. Deviations in the production schedule are attributed to the external initiative if they are caused by the generator's participation in the balancing market trade, commands received from the SO, or the operations of automation control devices in the power system. Failure to produce in accordance with the day-ahead market schedule for some other reasons causes deviations to be attributed to internal initiative of the generator. In the case of demand, the deviations between planned and actual consumption of customers with non-dispatchable load can be attributed to their external initiative only if they are caused by operation of power system automation. In all other cases, deviations are attributed to internal initiative.

The prices charged to market participants for their deviations depend on the cause of deviations. For example, if the generator fails to produce the scheduled amount of electricity, the missing amount must be purchased in the balancing market. Because the deviation is attributed to the generator's own initiative, the purchase price is defined by highest of the following prices: the day-ahead market price, balancing market price, or the generator's own day-ahead market price offer. Similarly, if the generator produces too much, the selling price is defined by the lowest of the following prices: the day-ahead market price, balancing market price, or the generator's own day-ahead market price offer. Table 1 shows the general principles for setting prices of deviations depending on the types of initiatives.

Table 1. Prices for deviations in the balancing market

Innitiative type	**Suppliers with price offers**	**Suppliers without price offers and suppliers with "quick " price taking offers**	**Consumers with dispatchable load**
External, up	Max (BM price, own DA price offer)	BM price	Min (BM price, own DA price offer)
External, down	Min (BM price, own DA price offer)	BM price	Max (BM price, own DA price offer)
Internal, up	Min (BM price, DAM price, own DA price offer)	Min (BM price, DAM price)	Max (BM price, DAM price, own DA price offer)
Internal, down	Max (BM price, DAM price, own DA price in offer)	Max (BM price, DAM price)	Min (BM price, DAM price, own DA price offer)

The total financial obligations and requirements of market participants in the balancing market do not coincide because of the different prices charged for the deviations. In case of positive imbalance, that is, if the total financial obligations of market participants exceed the total requirements, the excess is distributed among those market participants whose deviations were caused by external initiatives. If a negative imbalance takes place, that is the total financial obligations of market

participants are less than the total requirements, the deficit is collected from those market participants whose deviations were caused by internal initiatives.

2.2 Capacity market

Capacity market in Russia was designed to ensure resource adequacy in the period of peak demand. Initially, it was planned that capacity market will be in a form of competitive capacity auctions where new and old generators compete to be selected to cover the peak demand and get guaranteed payments. However, the immediate need for investments in new capacity as well as high market concentration led to the introduction of more detailed regulatory policies in capacity markets. The current capacity mechanism in Russia aims to guarantee the market entry of new generation, and to ensure sufficient income for the old generators.

The performance and price parameters of long-term capacity market are presented in two government decrees N89 on February 24, 2010 and N238 on April 13, 2010 (Russian government, 2010b). The System Operator (SO) defines the zones of free power flow that emerge during peak hours because of the inadequacy of the transmission capacity between the zones. In 2011, market was divided into 29 zones of free power flows. Figure 1 illustrates one zone of free power flow "West" and its interconnections with other zones.

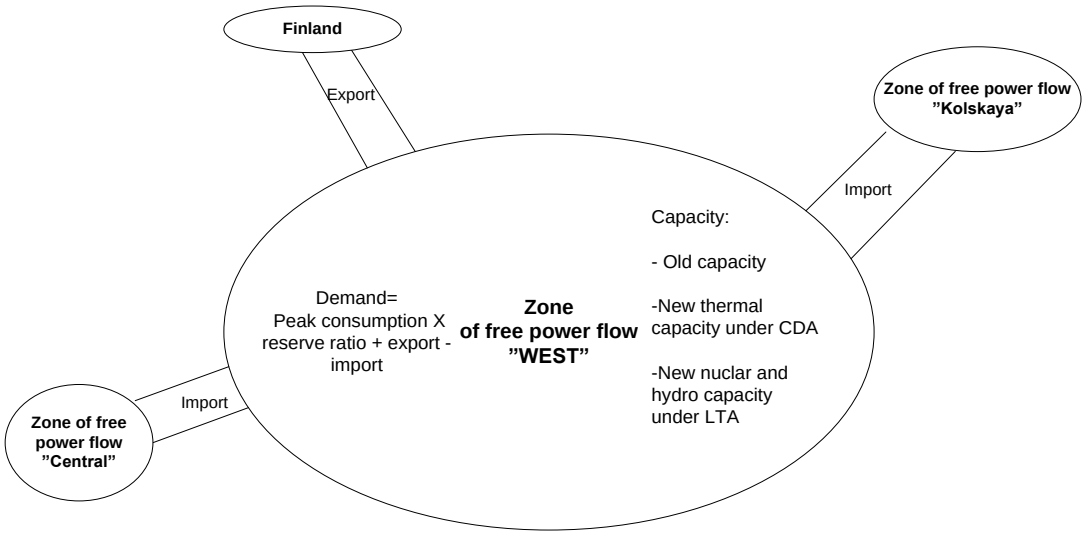


Figure1. Zone of free power flow "West".

For each zone, the SO estimates the peak demand (or capacity demand) for each month of the following year. Capacity demand of one zone of free power flow is the sum of capacity demands of different customers located in that zone. Capacity demand for the customers that cannot plan their own consumption is forecasted by the SO. Customers planning their own consumption notify SO about their planned capacity demand in a particular month. Once capacity demand is defined then the SO selects capacity of generators that can cover the demand. Generators participating in a Competitive Capacity Auction are classified into two main categories: old capacity (launched before 2007), and the new capacity (launched since 2007). Participation in the capacity market and the capacity payments are different for the old and new generation. New generators get guaranteed

fixed capacity payments and are prioritized in capacity auctions. The old generators compete with each others in Competitive Capacity Auctions. Capacity payments for new generators should cover investment and maintenance costs, while capacity payments for old generators should cover maintenance costs.

2.2.1 Contracts for new generation

The Russian government has issued a general plan for the development of the power sector based on the forecasted demand growth. With an average 2,2% annual demand growth (base scenario) and 3,1% (maximum scenario) and 67,7 GW of decommissioned old generation, the total need for new generation in 2010-2030 is estimated to be 173,4 (base scenario) and 228,5 GW (maximum scenario) (Russian Federation, 2010a). In 2010-2015, the entry of new generation capacity is incentivized by the capacity contracts between the government and the generators; Capacity Delivery Agreements (CDAs) for new thermal power plants, and Long-Term Agreements (LTAs) for new hydro and nuclear power plants (Russian government, 2010c). The investment programs issued for the generators are mandatory. Table 2 shows the volume of new generation capacity to be launched by each generating company in the period 2010-2015.

Table 2. Generators investment programs in 2010-2015.

GenCo	MW	Investor	GenCo	MW	Investor
WGK-1	1680	InterRAO	TGK-5	710	IES
WGK-2	1440	Gazprom	TGK-6	570	IES
WGK-3	2040	Norilsknike	TGK-7	475	IES
WGK-4	2510	Eon	TGK-8	890	Lukoil
WGK-5	800	Enel	TGK-9	1209	IES
WGK-6	1546	Gazprom	TGK-10	2360	Fortum
TGK-1	1360	Gazprom	TGK-11	352	InterRAO
TGK-2	1480	Sintez	TGK-12	400	SUEK
TGK-3	1557	Gazprom	TGK-13	320	SUEK
TGK-4	1092	Kvadra	TGK-14	27	Energomsbyt

Figure 2 illustrates the volume of thermal capacity to be launched under CDAs, volume of nuclear and hydro capacity to be launched by LTA for the years 2010-2015 and the total need for new generation forecasted in the general plan for the development of power sector in Russia.

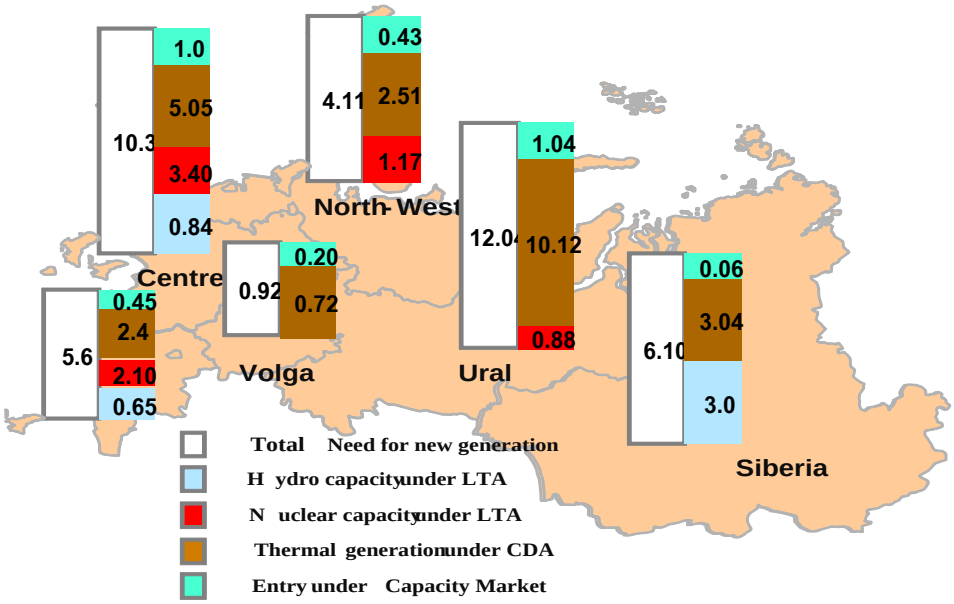


Figure 2. Need for new capacity.

According to CDAs, the investor has obligations concerning punctual commissioning of new generation, while the government guarantees a return on invested capital during ten years in the form of fixed monthly payments calculated based on typical investments costs of new power plant and fifteen years payback period. According to LTAs, the government guarantees a return on invested capital to the owners of nuclear and hydro power plants during twenty years in the form of fixed monthly payments calculated taking into account payback period of thirty years. Capacity payments depend on type of generation, location, etc. Typical capacity payments under CDAs are presented in Table 3. This mechanism is temporary and designed to solve the problem of an immediate need for new investments in generation sector (Gore, 2012). Based on the general plan for the development of the generation sector, this amount of capacity will almost cover the total need for capacity in the period 2010-2015.

Table 3. Capacity payments for new generators under CDAs, th.rub./MW,month.

	Gas power plans			Coal power plants	
Region	**> 250 MW**	**150-200 MW**	**< 150 MW**	**> 225 MW**	**< 225 MW**
South	500	617	771	1 048	1 130
South Volga	494	609	762	1 035	1 116
Center	524	647	810	1 100	1 187
Ural	554	685	858	1 165	1 257
Siberia	828	976	1 169	1 647	1 779

2.2.2 Competitive Capacity Auctions

Old generators (that have been launched before 2007) and new generators that are not under investment programs participate in Competitive Capacity Auction (CCA). The process of CCA is illustrated in Figure 3. The example concerns the capacity auctioned for 2013.

System Operator defines zones of free power flow	SO publishes information on minimum technical requirements for generators that can participate in CCA	FAS analyzes market concentration in zones and establishes price caps in zones with high concentration	Submission of capacity bids to CCAs	SO publishes the results of CCA: accepted generators, capacity buy and sell prices
01.06.2012	15.06.2012	1.08.2012	15.09.2012	25.09.2012

Figure 3. Process of Competitive Capacity Auction (CCA). (SO stands for System Operator and FAS stands for Federal Antimonopoly Service)

Before each Competitive Capacity Auction System Operator publishes the following information available for generators that want to participate in CCA (Regulation 19.3):

- Lists of zones of free power flow and transmission limitations between the zones
- Lists of zones where CCA are carried out applying price caps
- Capacity demand for each zone of free power flow
- Volume of capacity under CDAs and LTAs for each zone
- Technical requirements for generators participating in CCA

Before participation in CCA, generators have to pass the validation procedure, where for each generator the SO defines the maximum capacity that can be offered to CCA (Regulation 19.2). Validated generators cannot offer the capacity higher than a maximum capacity predefined by SO.

The capacity of generators to be selected in CCA is equal to the capacity demand in zone of free power flow minus share of demand that is covered by capacities of generators under CDAs and LTAs located in the same zone. Generators submit bids of monthly offered capacity (MW,month) and price (Rub/MW,month). The capacities of generators are selected in price-up order. Marginal pricing is applied, which means that the last accepted capacity bid forms capacity price for CCAs. The principle is illustrated on Figure 4.

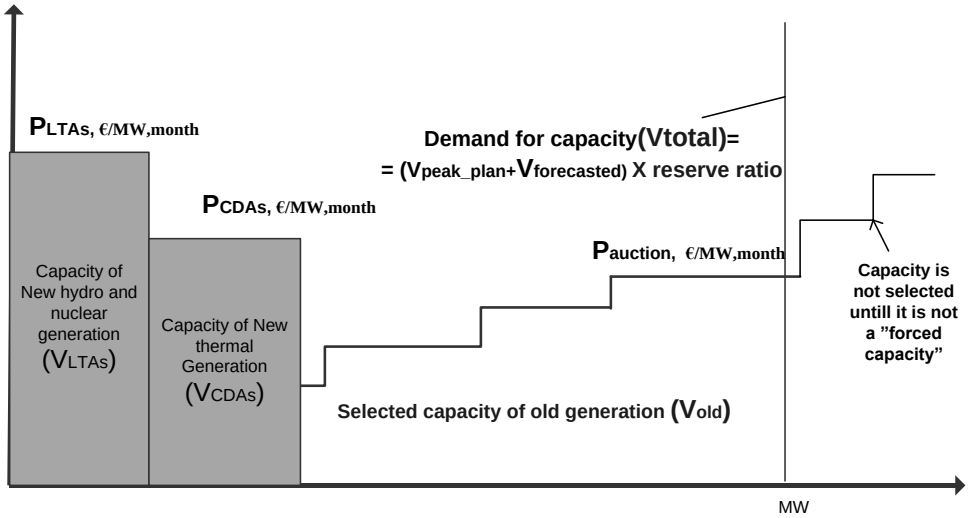


Figure 4. Price formation in Competitive Capacity Auction. V_{LTA} is the volume and P_{LTA} is the average price of new nuclear and hydro generation, V_{CDA} is the volume and P_{CDA} is the average price of new thermal generation, and V_{old} is the volume of old generation needed to satisfy the demand. The reserve ratio is defined by the SO (typically 17% of the peak demand).

The market concentration in the zones of free power flow is observed by the Federal Antimonopoly Service (FAS). In case of high market concentration (HHI>0,25)[(*1], price cap is applied in the CCA. In 2011, price cap was applied in 26 out of 29 zones of free power flow. The price cap is about 3000 Euro/MW,month.

There are generators that have not selected in the CCA, but whose operation is necessary for technical reasons such as maintaining reliability. This category of generators is classified as "forced" generators. Federal Tariff Service determines a regulated tariff for each "forced" generator. The information about the capacity and location of the "forced" generators is published by ATS every month (ATS, 2012a). For example, in November, 2012 there was only one "forced" power plant with installed capacity 73,5 MW in zone of free power flow "North-West".

Information on volumes of capacity accepted by results of CCA, volumes of capacity under CDAs and LTAs, "forced" capacity and price of CCA is published by System Operator for every month of the following year. Table 4 presents the results of capacity market for zone of free power flow "North West".

1 (* HHI = Herfindahl-Hirschman Index

Table 4. The results of capacity market for the zone of free power flow “North WEST”.

	January, 2012	January, 2013
Capacity under CDAs and LTAs in North West (MW)	1930	2350
Capacity accepted in CCA in North West (MW)	10791	9324
“Forced” capacity in North West(MW)	-	179
Total capacity under CDAs and LTAs for all zones	11056	14890
Price CCA (rub/MW,month)	118 125	127 937

2.2.3 Generators’ obligations

Capacity as a product means the readiness to produce electricity. For example, if a generator has been selected in the CCA and receives a capacity payment for 100 MW, the generator has to able to produce 100MW/h on request. Failing to do this leads to the reductions of the generator’s capacity payment. In addition, the generator is penalized for not fulfilling its obligations. Requirements for receiving the capacity payments include (Regulation 13):

- Participation in primary frequency control (except those generators that do not have technical ability to participate, e.g. some nuclear power plants)
- Participation in secondary frequency control (hydro power plants)
- Providing reactive power
- Readiness to produce electricity at maximum available capacity

In order to check of the fulfilment of the above requirements, the System Operator (SO) requests the performance data regarding, for example, the generators’ maximum available capacity and the controllability of the power plants. Deviations of the actual data from the data submitted to the SO for the CCAs are interpreted as the non-fulfilment of the requirements.

2.2.4 Demand side’s capacity cost

The capacity prices paid by the demand side reflect to total costs of capacity. The monthly capacity compensations for the generators under the CDAs and LTAs are collected from all the electricity users in the whole market. The capacity compensations to the generators accepted in the CCAs and the compensations to the “forced” generators are collected from the electricity users located in the same zones of free power flow where the generators in question are located. For example, the weighted capacity price for consumers located in zone of free power flow “North-West” is around 4000 Euro/MW,month. This price takes into account the remunerations paid to both old and new power plants under CDAs and LTAs.

At the end of each month, data on actual (measured) peak demands of capacity buyers during specific peak hours is gathered. There are usually 8-10 peak hours per day depending on a particular month. Information on peak hours is published by SO (SO-UPS Russia, 2012). Actual monthly capacity demand is defined as an average of the daily peak demands over a month. The daily peak

demand is the highest observed consumption during specific peak hours of the day defined by SO (see Figure 5). The monthly capacity payment is obtained by multiplying the average peak demand by the monthly capacity price.

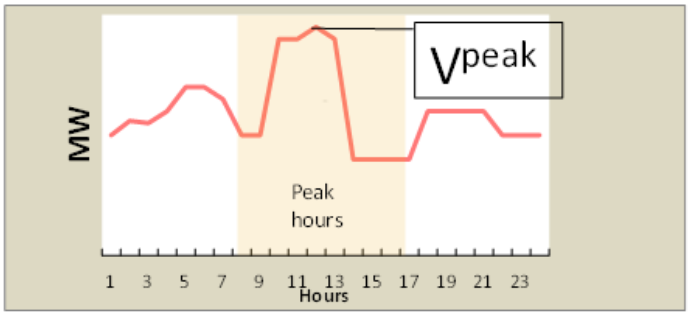


Figure 5. Peak demand.

2.2.5 Imports and exports in capacity market

The participation of import in the capacity market is possible. In the CCAs, import competes with the old generation capacity. However, in order to receive capacity payment, import would have to fulfil the availability criteria. In other words, the importer would always have to be able to deliver the volume of electricity indicated in its accepted CCA bid. Also, importer has to fulfil the requirements for receiving the capacity payments listed in 2.2.3.

Export is treated as demand in the Russian capacity market. Two months before the long-term capacity auction, the exporter has to submit a notification about the planned capacity demand to the System Operator. Exporter's capacity demand is taken into account when determining the total capacity demand for the long-term competitive capacity auctions. The actual monthly capacity demand of the exporter is defined as the average of the daily peak exports over a month. The daily peak export is the highest export volume during specific peak hours of the day.

2.3 Price drivers

The commissioning of new electricity generation capacity in Russia is likely to increase the demand side's capacity costs because the capacity payments for new generation are substantially higher than for the old generation. On the other hand, the entry of the new generation may result in lower electricity wholesale prices because the new power plants are expected to operate at lower incremental cost of production than the old ones. At the end of 2012, the Ministry of Economic Development of the Russian Federation conducted a market survey focusing on the effects of new generation capacity on the electricity prices. The study of the Ministry suggests that the introduction of the new capacities may lead to price reduction in the electricity wholesale markets on average by 3-4 % annually (until 2017 when the last generator under the existing capacity agreements for new generators is commissioned). In addition to the commissioning of new generation, the electricity wholesale price is Russia is also influenced by factors such as the amount of retiring old generation, the increase of demand, and the fuel prices, notably the domestic gas price in Russia.

In this study, the Russian electricity market was modelled as a simplified model illustrated in Figure 6. The model concerns the European part of Russia and Ural. Using the simplified model, it is possible to estimate how prices in the Russian electricity wholesale market may develop as result of the forecasted changes in the supply and demand. The modelling results are presented in Section 2.3.4.

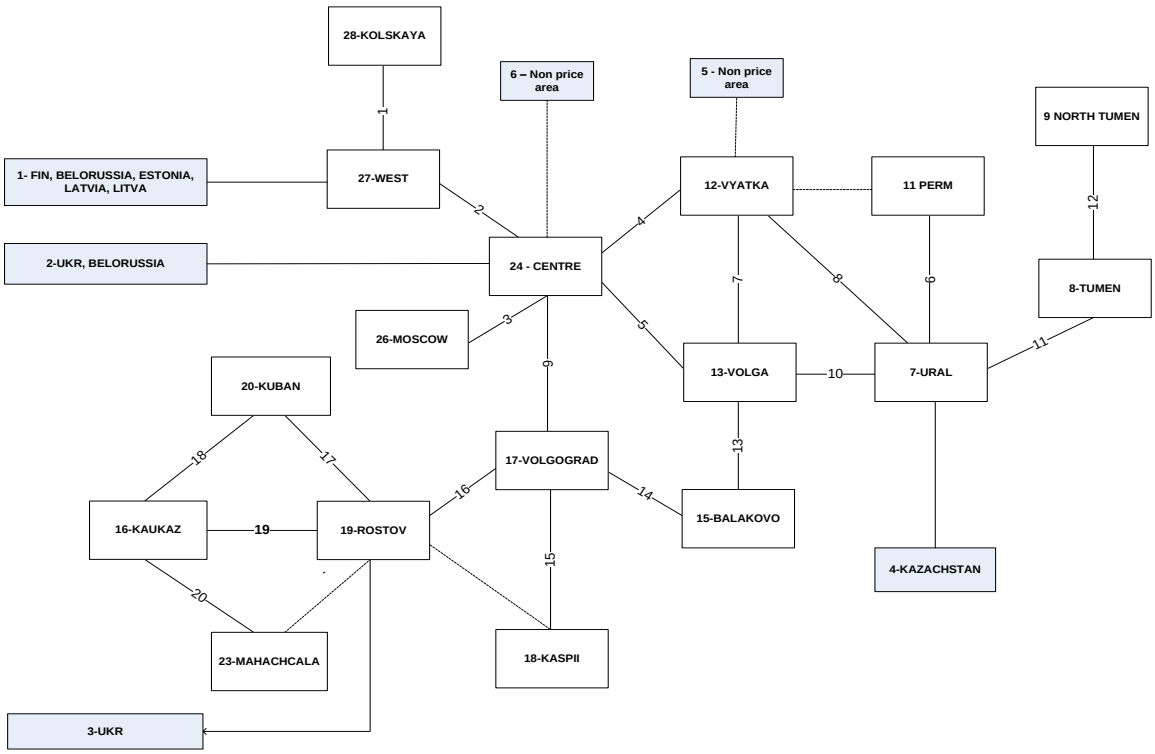


Figure 6. Simplified model of the transmission system in the European part of Russia and Ural.

2.3.1 New investments

One of the most important drivers of the Russian electricity market reform was to upgrade the electricity generation capacity, and the capacity contracts between the government and the generators have been the primary means to promote this goal. For example, in December 2010, the Ministry of Industry and Energy of Russia released the list of the thermal and hydro power plants that must be put into operation under the government contracts between 2011 and 2017 in Russia. The total capacity of the new thermal and hydropower stations planned for construction under the government contracts was about 31 GW. This data has been used as the main source of information to estimate the amounts of new thermal generation capacities entering the market in the coming few years. In addition, the investment plans of generation companies have been used to update and supplement the data of the Ministry of Industry and Energy. Furthermore, updated information concerning the commissioning of new large hydro and nuclear power plants has been collected from the Program of the Energy System Development of Russia published in June 2013. Table 5 summarizes the amount of new generation that can be expected to enter the markets in 2013-2016.

Table 5. Commissioning of new electricity generation capacity in the European part of Russia and Ural in 2013-2016.

Name	Amounts of new generation capacity, [MW]			
	2013	2014	2015	2016
Ural	1005	3387	1660	0
Tyumen	1250	0	420	0
North Tyumen	0	0	0	0
Perm	165	0	0	0
Vyatka	375	335	0	0
Volga	240	0	0	0
Balakovo	0	0	0	0
Caucasus	205	0	0	0
Volgograd	0	0	0	0
Caspii	235	0	0	0
Rostov	36	1330	0	0
Kuban	513	180	0	420
Makhachkala	0	100	0	0
Centre	1530	3195,5	1307	0
Moscow	1224,5	848	0	0
North-West	110	300	1170	1270
Kolskaya	0	0	0	0
Total	**7338,5**	**9375,5**	**5097**	**1620**

The offer prices submitted by the new thermal power plants to the electricity market can be estimated using information about the standard fuel rates of new thermal generation units and average regional gas and coal prices. In most cases, the new thermal generators can be estimated to enter the electricity market with offer prices that fall within the range from 12 to 24 Euro/MWh. However, part of the output of the thermal power plants is treated as must run generation that may submit only price-taking offers to the wholesale electricity market. The new nuclear and hydro power stations are also defined as must run generation that only submit price-taking offers.

2.3.2 Retirement of old generation

The Program of the Energy System Development of Russia also contains information on planned withdrawals of the existing generation units in 2013-2019. However, the Ministry of Industry and Energy defines the list of the existing power resources whose decommissions can be postponed if their removal jeopardizes reliable operation of the power system. Table 6 summarizes data on capacity reduction in the considered market sub-areas taking into account information on delayed withdrawals of the power units identified by the Ministry.

Table 6. Amounts of capacities put out of operation in the market sub-areas in 2013-2016 (Ministry of Industry and Energy, 2013).

Name	Amounts of withdrawn generation capacities, [MW]			
	2013	2014	2015	2016
Ural	12	361	280	729.5
Tyumen	0	0	0	0
North Tyumen	0	0	0	0
Perm	0	25	90,7	54,5
Vyatka	50	0	75	60,3
Volga	75	82,6	141,9	265
Balakovo	50	15	105	0
Caucasus	0	0	0	0
Volgograd	0	0	0	0
Caspii	0	0	0	0
Rostov	0	0	79.2	0
Kuban	0	6	0	95
Makhachkala	0	0	0	0
Centre	60	1147	1714,3	90
Moscow	18.3	0	192	206
North-West	110	1075	215	73,5
Kolskaya	58	0	0	0
Total	**345,3**	**2656,6**	**2837,6**	**1572,8**

2.3.3 Demand increase

The overall electricity demand in Russia is expected to increase and the large amount of new investments partially responds to this acknowledged need. For example, Table 7 shows the forecasted development of winter peak consumption in the European part of Russia and Ural in 2013-2016.

Table 7. Forecasted peak demand in the European part of Russia and Ural in 2013-2016 (SO UES, 2012).

Region	Peak demand, [MW]			
	2013	**2014**	**2015**	**2016**
Ural	21070	21347	21673	21998
Tyumen	10960	10901	10973	10980
North Tyumen	1006	1089	1115	1185
Perm	1681	1703	1729	1755
Vyatka	5712	5774	5873	5972
Volga	9045	9269	9474	9635
Balakovo	2205	2219	2239	2261
Caucasus	2870	2931	2990	3049
Volgograd	2917	2947	2972	3004
Caspii	767	788	801	814
Rostov	2924	3162	3270	3349
Kuban	4088	4420	4572	4683
Makhachkala	1091	1119	1202	1233
Centre	24382	24877	25403	25940
Moscow	17491	17826	18575	19226
North-West	10113	10450	10782	11067
Kolskaya	1957	1971	1991	2006

2.3.4 North West zone of free power flow

In 2012, the total installed capacity of power plants located in zone of free power flow North West was 14635 MW. Table 8 shows the forecasted peak demand in North West in 2013-2016, the amount of new generation that is planned to be commissioned, and the amount of old generation that is planned to be decommissioned in 2013-2016 based on the forecast of Ministry of Industry and Energy (Ministry of Energy of Russia, 2013). North West zone can be considered as an oversupply area with 30% higher available capacity than the capacity needed to meet forecasted peak demand. Part of the excess capacity (around 17%) is due to reliability considerations.

Table 8. Capacity in zone of free power flow “North WEST” (in MW)

	2013	2014	2015	2016
Forecasted domestic peak demand	10113	10450	10782	11067
Commissioned nuclear capacity	-	-	1170	1170
Commissioned thermal capacity	110	300	-	100
Decommissioned nuclear capacity	-	1000	-	-
Decommissioned thermal capacity	110	75	215	-
Total installed capacity in North West	14635	13860	14815	16085

2.3.5 Price modelling

Using the simplified model of the Russian electricity markets, electricity price development in three different cases was considered. In the first case, it was assumed that the market develops as forecasted; that is, the new generation enters the markets as scheduled, the old power plants retire as planned, and the demand develops according to the forecasts. The domestic gas price is assumed constant. The second case assumed that the new thermal generation enters the market with a six month delay (the rationale being that in reality the new power plants tend to be commissioned with time delays). Gas price is assumed constant in this case as well. Table 9 shows the modelled average daily winter and summer prices in the North-West Russia in 2013-2016 in the first two cases.

Table 9. Modelled daily average winter and summer prices in the North-West Russia in 2013-2016.

Scenario	Daily average prices, Euro/MWh						
	Winter 2013	Summer 2014	Winter 2014	Summer 2015	Winter 2015	Summer 2016	Winter 2016
1	26,0	26,0	23,2	24,3	23,0	23,7	24,3
2	27,6	27,1	28,4	24,4	27,5	23,7	25,7

The third case is otherwise similar to the second case but it was now assumed that the domestic gas prices in Russia are increased by 15 % annually in 2014-2016, in accordance with the forecasts of the Ministry of Economic Development of Russia. Figure 7 and Figure 8 demonstrate the impact of annual gas price increases on the modelled electricity prices in winter and summer periods.

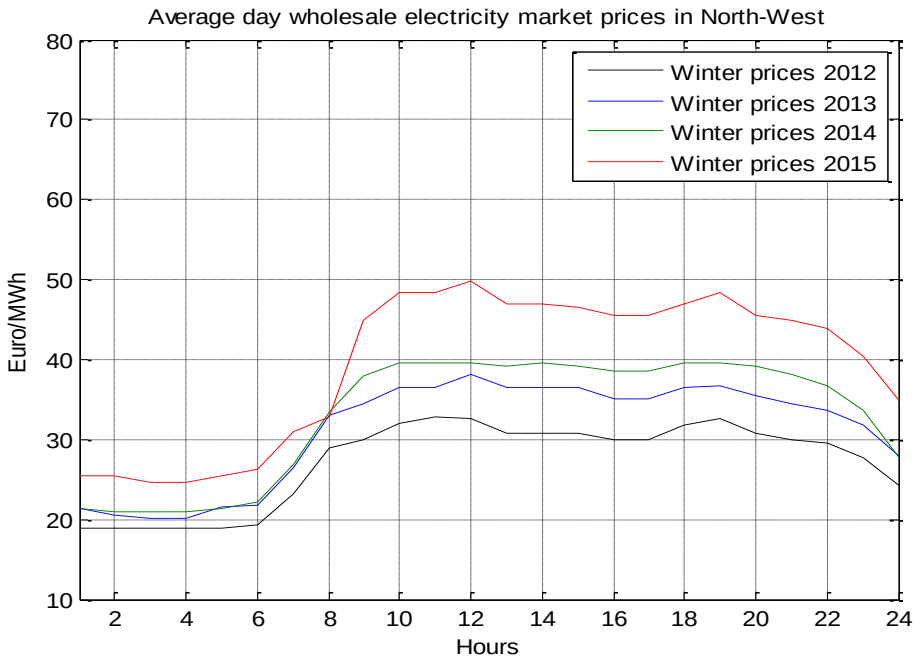


Figure 7. Average daily winter price in the North-West Russia in 2012-2016 assuming increasing gas prices.

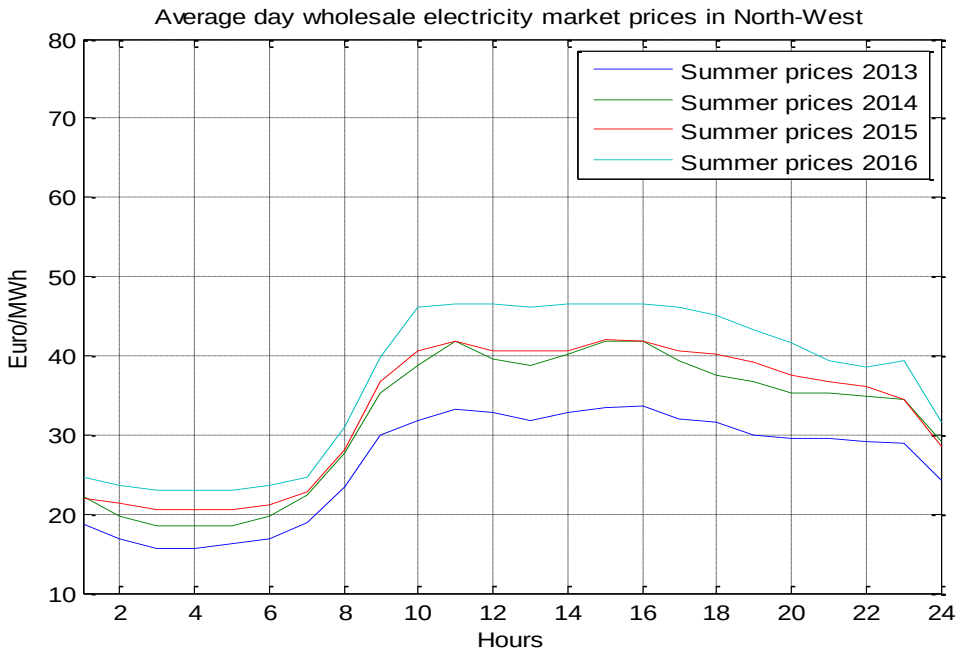


Figure 8. Average daily summer prices in the North-West Russia in 2012-2016 assuming increasing gas prices.

3. Electricity trade between the Nordic and the Russian markets

Russian and Nordic electricity markets interact on the border of Finland and Russia. The Nordic market is an energy-only market where as the Russian market rewards generators for both the output (electricity market) and for the availability of electricity generation (capacity payment). At present, the trade is possible only from Russia to Finland, and the use of interconnector capacity is assigned to the Russian state-owned company InterRAO. The interconnector capacity is 1400 MW in total (consisting of two DC links and one AC line).

Until recently, the consumers in the higher-cost Nordic region have had access to lower-cost Russian electricity. However, since the introduction of the capacity markets in the Russia, the volume of trade between two markets has been significantly reduced. For example, in 2012, the annual electricity flow from Russia to the Nordic market fell almost by two thirds (from about 12 TWh/a to about 4 TWh/a).

In this section, we will analyze the impacts of replacing the monopolistic trade arrangement between two electricity markets with more market-based cross-border trade arrangements. The analyzed markets resemble the Finnish and North-West Russian electricity markets. Our analysis focuses on the modelling electricity trade between the two interconnected markets for which we have constructed the supply and load duration curves. We will examine the use of the interconnector under different cross-border trade arrangements. Furthermore, we will assess the economic impacts of changing the cross-border trade arrangements through welfare analysis. Finally, we will discuss the difficulties of integrating electricity markets with different designs.

3.1 Modelling cross-border trade

We will study the use of the interconnector and the welfare impacts of trade in five different cases.

1. The first case assumes a monopolistic trade arrangement. The flow is unidirectional (from the “North-West Russian” market with capacity mechanism to the “Finnish” energy-only market). The exporter pays a capacity payment that depends on the volume of export.

2. The second case also assumes a monopolistic use of the interconnector but allows for a bidirectional flow of electricity across it. Export is treated as demand in the market with capacity mechanism (i.e. export is charged with capacity payment) and import is treated as generation (i.e. import receives capacity remuneration).

3. The third case studies the cross-border flow when market coupling is used and the trade volumes are determined by the day-ahead price differences between the markets. Capacity costs are allocated to the consumers in the market that has a capacity mechanism in place.

4. The fourth case also builds on market coupling but assumes redistribution of capacity costs to consumers in both markets.

5. The fifth case looks at the use of the interconnector in the case of explicit auction of the interconnector capacity. Export is charged with a capacity payment and import receives capacity remuneration. In the cases of explicit auction, conclusions on cross-border trade are not based on modelling; instead, analytical approach is taken, mainly because of the difficulties in modelling market players' behavior. In this respect, Case 5 differs from the above Cases 1-4, which rely on modelling the cross-border flow with the two-market-model.

Cases 1-4 are presented in Sections 3.1.1-3.1.4, and case 5 in Section 3.2.

3.1.1 Two-market-model

In our analysis, Market A is energy-only market (similar to the Finnish price area of the Nordic market). Market B is a capacity-based market (similar to the North-West Russian market, or the zone of free power flow). Market B is an oversupply area. Markets A and B are interconnected by the DC link of 1400 MW. Marginal cost curves for both markets are approximations of their cost-based merit order curves in summer and winter periods. These curves were constructed using the data on average electricity production and marginal costs of production of each particular technology (hydro, nuclear, CHP, gas and coal fired generation) in summer and winter seasons. Figure 9 and Figure 10 illustrate the approximated supply curves in market A and B for summer and winter. In constructing the supply curves, we assume that generators bid their marginal costs to the spot markets. Summer and winter supply curves differ because of the differences in the availability of hydro generation and CHPs.

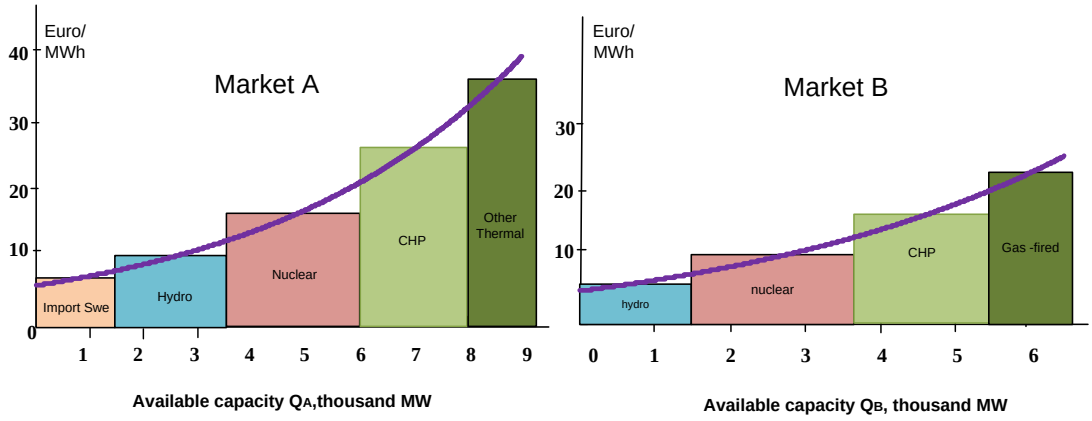


Figure 9. Cost-based merit order curves in markets A and B (summer).

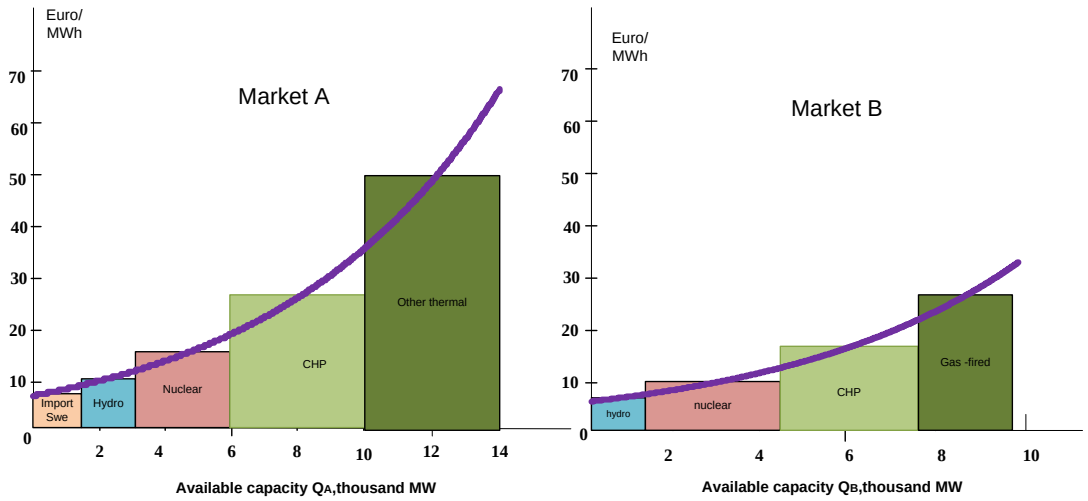


Figure 10. Cost-based merit order curves in markets A and B (winter).

We assume inelastic demand in both markets. Variation of demand over time is defined by a load duration curve. To simplify, demand in markets A and B are assumed to be perfectly correlated, i.e. any given demand A also determines demand B. The load duration curves are calibrated using statistic data on demands in both markets. The strategy of the monopolistic cross-border trader is different in off-peak and peak hours because of the capacity market rules in market B. Therefore, four different load duration curves were calibrated for off-peak and peak periods in winter and summer seasons. The results are presented in Figure 11 and Figure 12.

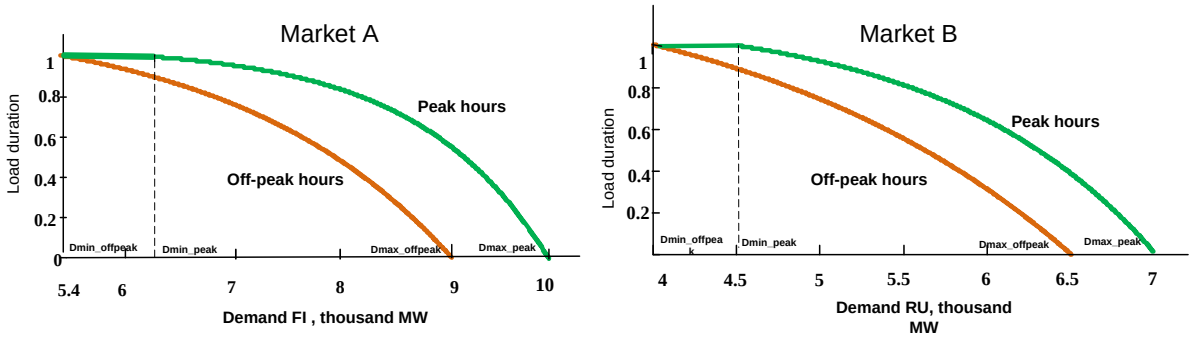


Figure 11. Load duration curves in markets A and B (summer).

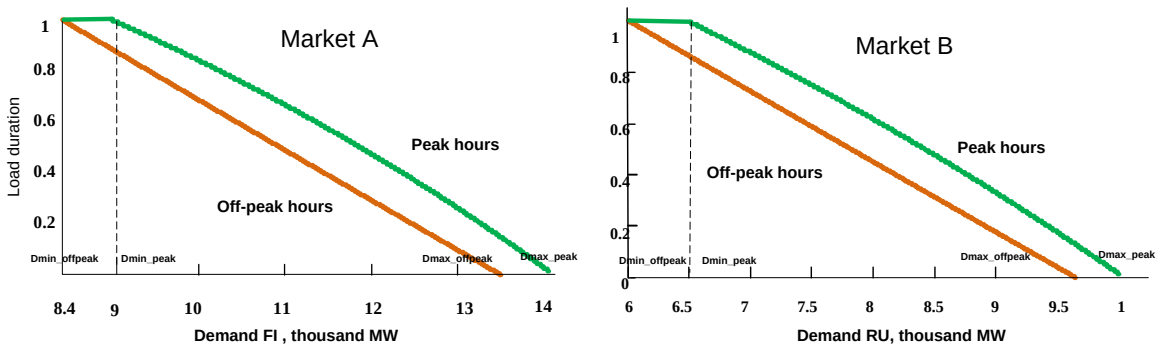


Figure 12. Load duration curves in markets A and B (winter).

The capacity mechanism in market B is modeled as follows. In principle, the total capacity demand is sum of forecasted domestic demand multiplied by the reserve ratio. Additionally, imports and exports can be taken into account when determining the total capacity demand in market B. Table 10 presents the parameters used to quantify the capacity market in our modeling.

Table 10. Parameters of capacity market.

Market B	**Summer**	**Winter**
Domestic peak demand	7000 MW	10000 MW
Capacity price Cp	3500 €/MW,month	4000 €/MW,month
Reserve ratio	1.17	

3.1.2 Trade arrangements

Case 1. Cross-border trade is assigned to one monopoly trader, who decides independently the volumes of the cross-border trade. Flow can be only from market B to A. The cross-border trader buys electricity from the day-ahead markets in the export market B, and sells it in the day-ahead market of the import market A. Cross-border flow shows as supply in market A and as demand in market B. In both day-ahead markets A and B, electricity is traded on hourly basis. During peak hours, the cross-border trader faces a capacity payment in the export market B. The cross-border trader's capacity charge is the maximum export in any of the peak hours of the day multiplied by the capacity price. The cross-border trader also pays transmission charges for the use of the interconnector. The payment depends on the actual cross-border flows.

We assume that the cross-border trader operates under perfect information, i.e. the cross-border trader is aware of (can observe) supply functions and average demand in off-peak and peak hours of a certain day. Thus, cross-border trader can estimate the impact of cross-border volumes on electricity prices in both markets. The cross-border trader maximizes its profit while deciding

separately on the optimal cross-border flow for peak and off-peak hours. In off-peak hours, the profit is driven by the expected price difference between the markets, and the transmission tariff. In peak hours, the optimal cross-border flow is driven by the expected price difference, the transmission tariff, and the capacity price.

Case 2. Trade is possible in both directions. The cross-border flows and their directions are subject to profit optimization of the trader. In off-peak hours, the optimal volume and direction of cross-border flow is subject to the expected price difference between the markets, and the transmission tariff. In peak hours, the optimal volume and direction of the cross-border flow is subject to the expected price difference between the markets, the transmission tariff, and the capacity price. We assume that if the trader exports from A to B, then the trader receives capacity payment equal to the maximum export during peak hours multiplied by the capacity price. If the trader exports from B to A then a capacity payment is charged from the exporter. The amount of payment is the maximum export during the peak hours multiplied by the capacity price.

Case 3. Market coupling is applied to optimize the flow between market A and B. The direction and volume of flow is determined on the basis of electricity prices in both markets. Imports and exports are excluded from the capacity markets (i.e. no capacity charge is imposed to export, and the import does not receive a capacity remuneration in market B). Market coupling aims to make use of the interconnection capacities in the most efficient way. The optimization problem involves the demand and supply in different markets (power exchanges) that need to be matched in order to maximize the total gains from trade (i.e. the increase in welfare). The objective function is to maximize overall social welfare in both markets under the constraints of the available transfer capacity between them. In our analysis, the optimal cross-border flows are subject to the overall market welfare maximization (i.e. the sum of producer and consumer surpluses in both markets, see Figure 13).

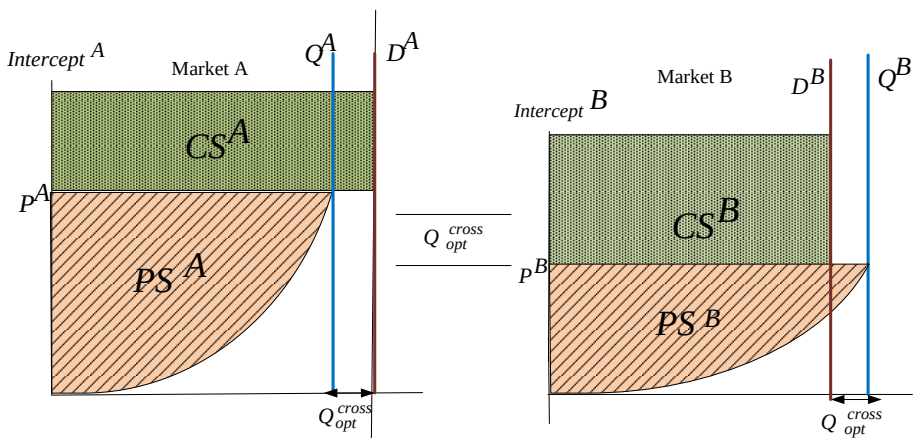


Figure 13. Producer and consumer surpluses in markets A and B.

In Figure 13, PS^A and PS^B are the producer surpluses in markets A and B, respectively. They reflect the benefit (or surplus) that the producers gain from selling their product at a market price that is higher than the price at which they would be willing to sell. Similarly, CS^A and CS^B represent consumer surpluses in both markets. They indicate the benefit to consumers from being able to buy electricity at a price that is lower than the price that they would be willing to pay. The $Intercept^A$ and $Intercept^B$ reflect the prices that the consumers would be willing pay, Q^{cross} is the electricity flow

between the markets, and Q^A and Q^B are the volumes of cleared generation in markets A and B, respectively.

Case 4. Similar to Case 3, market coupling is used to optimize the flow between markets A and B. The difference is that in Case 4, the capacity mechanism in market B concerns also the cross-border trade. Export from market B pays a capacity charge, and the import to market B receives capacity remuneration. In addition, consumers in market A are made responsible for paying for the "additional" capacity in market B. The amount of the "additional" capacity corresponds to the volume of net transfer capacity (NTC) of the interconnector. In modelling, it is assumed that the TSO in market A reserves the necessary capacity in market B, and adds the capacity cost to the transmission tariffs of the consumers in market A.

3.1.3 Results

This section presents the results of the cross-border flow optimization under different trade arrangements. The cross-border trader's avoidance of capacity costs in Cases 1 and 2 leads to reduced flows during peak hours. The introduction of market coupling in Cases 3 and 4 increases the trade volumes. The summertime flows in off-peak and peak hours in different cases are show in Figures 13 and 14, and the wintertime off-peak and peak hour flows in Figures 15 and 16.

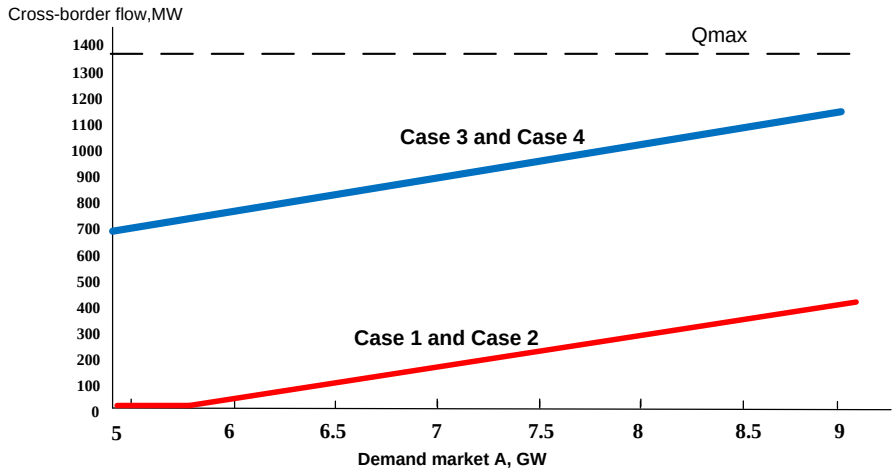


Figure 13. Cross-border power flow, summer off-peak hours.

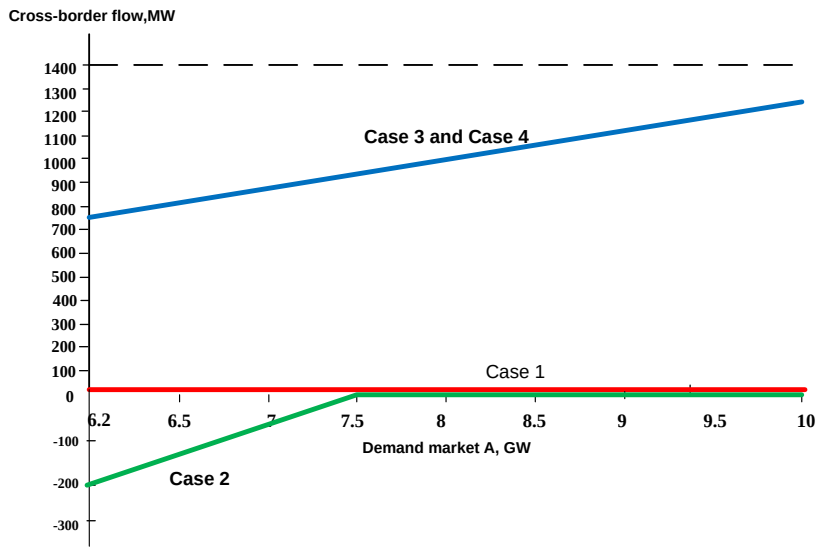


Figure 14. Cross-border power flow, summer peak hours.

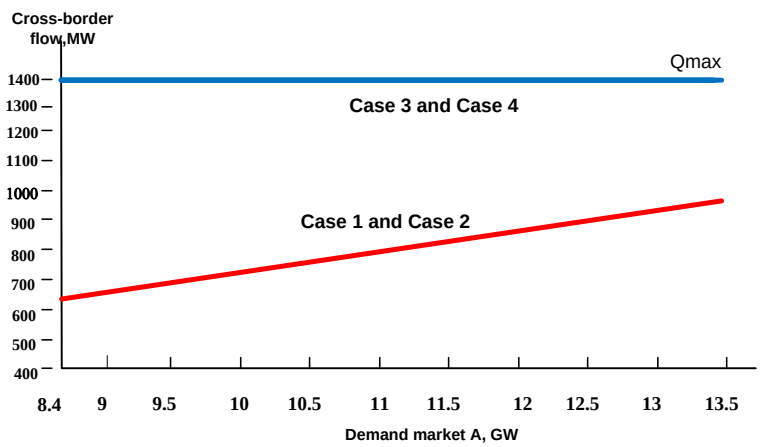


Figure 15. Cross-border power flow, winter off-peak hours.

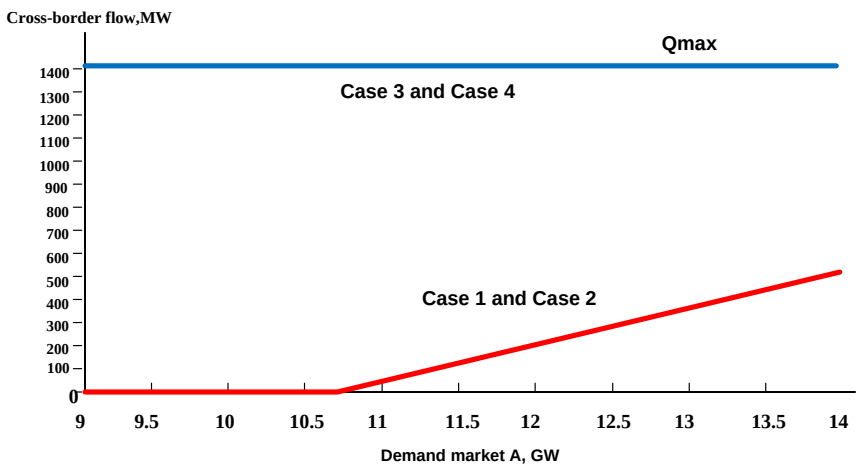


Figure 16. Cross-border power flow, winter peak hours.

The total energy transmitted through the interconnector between markets A and B over a three-month summer period and a three-month winter period is illustrated in Figure 17. Market coupling in Cases 3 and 4 lead to four times higher total trade volume compared to the monopolistic trade arrangement in Cases 1 and 2.

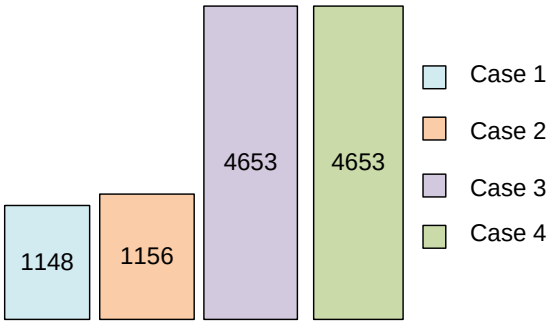


Figure 17. Cross-border energy flow (GWh).

Case 1. Capacity market creates a barrier to cross-border trade. This can be seen as significant reduction of power flow during peak hours when export from market B is subject to capacity charges. Even if the electricity price spread (the difference between day-ahead electricity prices in the two markets) would justify the cross-border trade during these hours, the capacity mechanism may prevent it. The cross-border trader finds it profitable to export electricity from market B to A only when the price difference is over 20 Euro/MWh (i.e. when the price difference is 0-20 Euro/MWh, it is not rational to export electricity from market B to market A at all; the 20 Euro/MWh threshold follows from dividing the monthly capacity price by the number of peak hours in a month). An example of the "dead-band" in the cross-border flow in winter peak hours in shown in Figure 18.

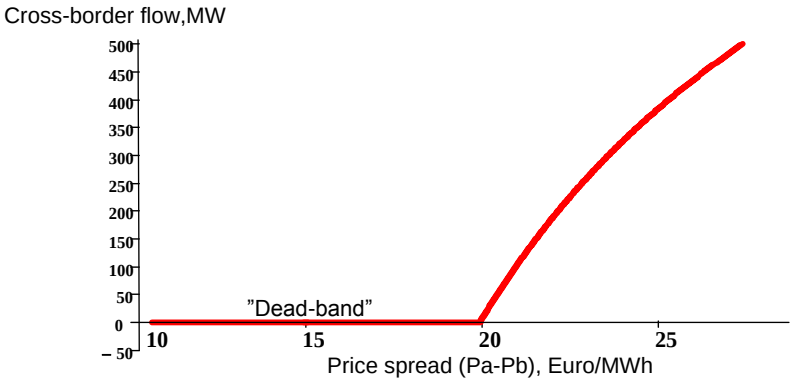


Figure 18. "Dead-band" in cross-border trade caused by capacity price in Case 1 in winter peak hours. When the price difference between markets A and B is less than 20 €/MWh, it is not rational to trade electricity, which leads to zero flows across the interconnector.

Case 2. In this case, the trade arrangement is monopolistic but allows for bidirectional trade between the markets A and B. If the cross-border trader imports electricity from market A to market B during specific peak hours, it receives a capacity payment. During summertime peak hours, the

capacity mechanism may create an incentive to import from market A to market B against the electricity price difference (i.e. when the day-ahead electricity price is higher in market A than in market B). This creates a problem of inverse cross-border flows, which can be considered as inefficiency of cross-border trade and can affect the welfare in both markets. The problem of inverse cross-border flow during summer peak hours is illustrated in Figure 19.

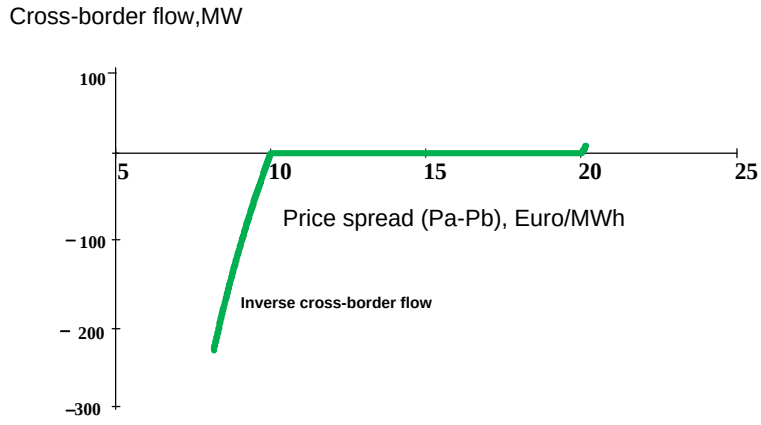


Figure 19. Inverse cross-border flows during summertime peak hours.

Case 3. In case of market coupling, the optimal cross-border flow is not a subject of monopolistic decision but the aim is to optimize the volume of trade to obtain welfare gains. Since the capacity mechanism does not concern the cross-border trade, the flow is determined on the basis of the day-ahead electricity price differences in markets A and B alone. This leads to higher utilization rate of the transmission link compared to Cases 1 and 2 with monopolistic use of the interconnector capacity (e.g. the volume of trade in Case 3 is 4658 GWh in six months against the 1148 GWh in Case 1). Market coupling is a feasible way to organize the cross-border trade even when the market designs differ. However, the existence of unilateral capacity payment in market B may give raise to concerns about the distributional effects that may be political in nature. For example, the consumers in the capacity-based market B may be considered as having to pay for the additional generation capacity while the consumers in the neighbouring energy-only market A benefit from the lower electricity prices without having to pay for the extra capacity.

Case 4. Incorporating capacity mechanisms in the cross-border trade is an attempt to eliminate some of the distributional effects caused by the coupling of the two markets with different market designs. In our modelling, we assume that the TSO in market A reserves the capacity in market B. The volume of the reserved capacity equals the NTC of the interconnector, and the capacity costs are included in the transmission tariffs of the consumers in market A. The volume of cross-border trade is higher in the case of market coupling than it is the case of monopolistic use of the interconnector. However, according to our analysis, market A as whole does not significantly benefit from the increased trade.

3.1.4 Welfare analysis

In the welfare analysis, we calculate the producers' and consumers' surpluses in markets A and B, the TSOs' incomes, and the profit of the cross-border trader over the studied six-month period (three summer months and three winter months). Figure 20 illustrates the producers´ surpluses in the day-ahead electricity market in markets A and B, and the producers' capacity remunerations in market B.

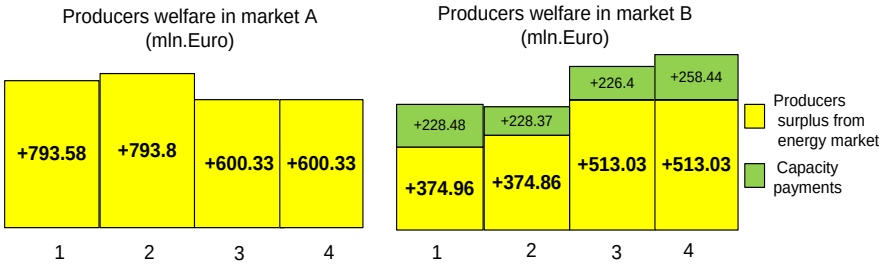


Figure 20. Producers' surpluses in day-ahead electricity markets in markets A and B, and the producers' capacity remunerations in market B over the examined six-month period.

Figure 21 illustrates the consumers´ surpluses in day-ahead electricity markets, the consumers' capacity payments, the TSOs' incomes, and the cross-border traders' profit in markets A and B over the examined six-month period. In Cases 1 and 2 (i.e. under monopolistic cross-border trade arrangements), the TSOs' income is calculated by multiplying regulated tariff with cross-border flows. The regulated tariff is assumed to be 5€/MWh. In Cases 3 and 4 (i.e. under market coupling), the TSOs' income is the price difference between two markets multiplied by the cross-border flow (i.e. congestion income). TSOs' incomes are distributed equally between the consumers in markets A and B.

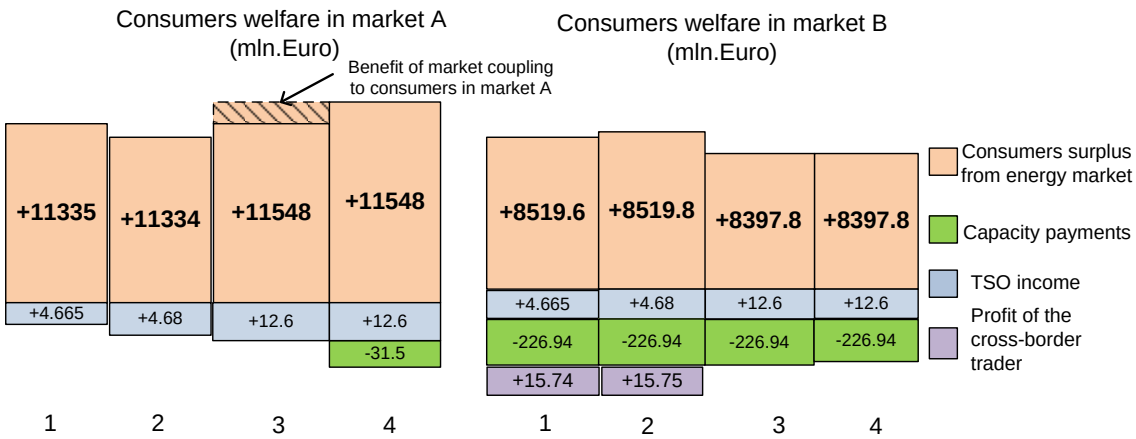


Figure 21. Consumers' surpluses in day-ahead electricity markets, the consumers' capacity payments, the TSOs' incomes, and the cross-border trader's profit in markets A and B over the examined six-month period.

In terms of total market welfare, market coupling is the most attractive option. With the assumed supply-cost structures in the two markets, the welfare benefit of market coupling is around 32,5 million Euros in the analyzed six-month period when compared to the monopolistic cross-border trade. The benefit of the increased trade can be explained by the high diversity in the supply-cost structures in the markets, and thus considerable price difference between two markets (15€/MWh on average). However, the welfare gain is very sensitive to the price spread between two markets. For example, simply assuming a 15% domestic gas price increase in market B (where gas is the fuel used by the generators setting the price at the margin) would lower the welfare benefit of market coupling from 32,5 to 22 million Euros over the examined six-month period (for comparison, see the Figures 7 and 8 on pages 21 and 22 for the impact of gas price increases on the development of Russian electricity wholesale prices in winter and summer periods). The results of the welfare analysis in markets in markets A and B separately and in total are presented in Table 11.

Table 11. Results of welfare analysis.

	Total Welfare (market A, mln.€)	Total Welfare (market B, mln.€)	Total Welfare (market A+B, mln.€)
Case 1	12133,2	8917,0	21050,2
Case 2	12132,5	8917,1	21049,6
Case 3	12160,9	8923,4	21084,4
Case 4	12129,4	8954,9	21084,4

The decrease in overall welfare in Case 2 compared to Case 1 is caused by the inverse cross-border flows (i.e. the electricity flow is from the higher price market to the lower price market). The reason for the inverse flows in Case 2 is that import is assumed to receive capacity remunerations in market B. The inverse flows can be considered as inefficiency of cross-border trade, and they have an impact on welfare in both markets.

3.2 Possibilities of explicit auction

In the fifth case, we analyze the possibilities of using explicit auction in allocating the interconnector capacity between the two markets A and B. In explicit auction, the transmission rights are auctioned independently of the transactions in the day-ahead electricity markets. Transmission rights are sold on yearly, monthly or daily basis. In the transmission rights auction, generators bid the price and quantity (i.e. specify their willingness to pay for the requested transmission capacity). The bidders have to define the injection zone, the withdrawal zone, the amount of energy transmitted and the transmission capacity unit price. Finally, the transmission market is cleared by the lowest accepted bid. After obtaining transmission capacity rights, generators can trade electricity via the interconnector. For example, generators who acquire the rights to use the transmission capacity for export can bid electricity in the neighbouring day-ahead electricity market.

In our analysis, we assume that export from market B pays capacity charge and the import to market B receives a capacity remuneration, both of which depend on the actual flows. Bidirectional trade is possible. Auction of the transmission rights is held by the TSOs in markets A and B. Market A is an

energy-only market and market B is a capacity-based market. In market B, foreign generators can compete with old generation in annual Competitive Capacity Auctions to get capacity remunerations. In order to get capacity payment, import has to be available during peak hours. In other words, during the peak hours, the importer has to bid to the day-ahead market the same volume that was indicated in its accepted capacity bid. The cross-border flow is the outcome of the generators' decision-making, driven by the expected profits in markets A and B. Efficiency of the use of the interconnector depends on the accuracy of the market participants forecasts concerning the day-ahead electricity prices in markets A and B.

Generators in markets A and B face a trade-off between getting a higher day-ahead electricity price in market A and accepting a lower electricity price but fixed capacity payment in market B. For example, a generator in market A may have two options: sell part of the output in market A, and the remaining in market B. In order to sell in market B, a physical transmission right is required.

If we assume that generators can get a capacity remuneration of 3000 €/MWh,month in market B (about 15€/MWh if we allocate the monthly capacity price to the total number of peak hours per month, i.e. for approximately 200 hours) and that the transmission auction price is 5€/MWh, then we can estimate the generators' cross-border trade strategies under different price spreads between markets A and B. Figure 22 illustrates the price spreads and their durations between markets A and B.

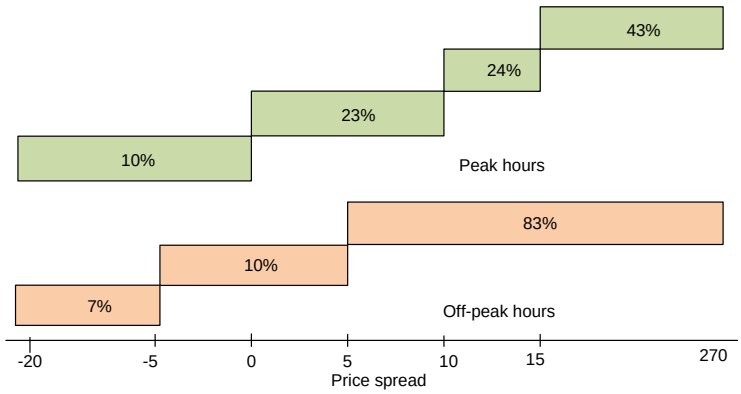


Figure 22. Price spreads between markets A and B and their durations.

For example, it can be seen in Figure 22 that the price spread of -20€/MWh to -5€/MWh between markets A and B is observed during 7% of the off-peak hours of the year. Because of the higher electricity prices in market B than in market A during these hours, generators in market A with marginal costs below the expected spot electricity price in market B are the potential buyers of the transmission rights. During 83% of off-peak hours the price spread is 5€/MWh or higher, and the generators in market B with marginal costs below the expected spot electricity price in market A are the potential buyers of the transmission rights.

For about 33% of the peak hours, the price spread is between -20€/MWh and 10€/MWh. During these hours, it would be profitable for the generators in market A with marginal costs below the expected spot electricity price in market B to sell electricity in market B, where they can also receive

capacity payments. Furthermore, when the price spread is between 0€/MWh to 10€/MWh, inverse cross-border flows may occur. The inverse flows are caused by capacity payments. Let us consider an example. We assume prices to be 30 €/MWh in market A and 25 €/MWh in market B. In addition, the generators' capacity remuneration in market B is 15€/MWh and the transmission rights are 5€/MWh. If a generator that is located in market A sells its output in market B, it gets the market price of 25 €/MWh for its output, receives a capacity remuneration of 15 €MWh, and pays 5€/MWh for the transmission rights. The profit of the generator is (25+15-5)€/MWh = 35€/MWh, which is more than the 30€/MWh it could get in market A. Hence, because of the capacity remuneration available in market B, the generator in market A has incentives to trade against the price difference in the day-ahead market.

During 43% of the peak hours the price spread is higher than 15€/MWh, and the generators in market B have incentives to acquire the transmission rights to be able to sell their electricity in market A (i.e. expected profits from electricity selling in market A are higher than the sum of the day-ahead electricity market revenues and the capacity remunerations in market B).

Strategies for reserving the transmission rights might be different for baseload and peak generators. For example, a peak generator in market A with marginal costs above the expected spot price in market B might still find it more profitable to sell energy to market B in peak hours in order to receive a stable 3000 €/MW,month for providing its capacity to market B than to sell its output in market A only for few hours per month. However, in order to receive the capacity payment, the peak generator would have to the acquire transmission rights for all the peak hours of the month, even if it was actually dispatched only during few of those hours in market B.

4. Discussion

Our study has looked at the drivers and prospects of cross-border trade between the Nordic and Russian electricity markets and analyzed the present use of the interconnector between Finland and Russia. In addition, we have modelled the flows of across the interconnector under different trade arrangements. The current setting of the cross-border trade between Nordic and Russian markets is one of the few test cases that allows for empirical analysis of the interaction of an 'energy-only' (Nordic) market and a capacity-based (Russian) market. The PJM-MISO case in the US and the Ireland-UK case are two other examples, where the capacity payments play a role the interregional/cross-border electricity trade. From these cases, some lessons can be drawn for Europe to contribute to the discussion about the possible role and impacts of capacity payments on the development and functioning of the internal electricity market.

4.1 Prospects of Nordic-Russian cross-border trade

Our findings suggest that the differences in the market designs may impede cross-border trade and result in inverse flows. Market coupling in principle could increase the trade but it may also result in problematic distributional effects. To estimate the long-term impacts of replacing the monopolistic cross-border trade with market coupling, projections of welfare benefits with respect to changes in future supply-cost structures in both markets should be made. In the long-term analysis, potential for export from Finland to Russia should be examined as well. For example, in the period of high hydropower output in Scandinavia, prices in Finland can be lower than in Russia (5% of the hours of the whole year, according to the electricity price statistics for 2012). During these hours, it would be feasible to export electricity from Finland to Russia. In addition, the possible increases in the domestic gas prices in Russia and the construction of new nuclear power in Finland may further increase the prospects of electricity exports from Finland to Russia. At present, the technical characteristics of the transmission link limit the possibility of bidirectional trade. However, the project can be feasible if the benefits (e.g. the welfare gains from increased trade) are higher than the costs of the reconstruction of the link. Assuming an investment cost of 160 million Euros (here we refer to the estimated costs of a DC link between Lithuania and Poland), a 15% discount rate, and a 20 year payback period, yields the annuity of 25 million Euros for the reconstruction project.

4.2 Other markets

4.2.1 PJM-MISO

PJM Interconnection (Pennsylvania- New Jersey- Maryland) applies uses nodal pricing in the day-ahead electricity markets. PJM market also has a separate capacity market to guarantee sufficient revenues for generators and incentivize new entry. Mid-West ISO (MISO) control area is next to the PJM market. It also applies nodal pricing, and has a capacity market in place. PJM and MISO markets are connected through interconnectors. Both markets have their own organizations responsible for dispatching. Interregional trade between the two markets has taken place since early 2000s. However, nowadays the difference in capacity prices in the two markets seems to complicate the short-term trade between the two markets. Problems exist especially in combining the short-run

dispatch with the long-run interconnector capacity reservation (MISO, 2011; MISO, 2012; The Brattle Group, 2011). For example, in 2010, 56 % of time the electricity flow was from high price area to low price area.

4.2.2 UK-Ireland

Ireland and Northern Ireland form an all-island electricity market. The electricity pool is mandatory for all market participants and generators are dispatched centrally. Energy offers are submitted day before the delivery to dispatch generators and to calculate pre-prices (1/2 hour time periods). The actual prices are calculated on the fourth day after delivery. In all-island region, the Capacity Payment Mechanism (CPM) is introduced to cover the fixed revenue for generators. The revenue is a regulated quantity and paid for providing the generation capacity to the markets. Money is collected from retailers buying electricity from the pool (CER, 2011; National report Ireland, 2011). Total capacity payment each year is a fixed payment: Total Capacity Payment = Total Required MW (demand forecast) x Annual Cost of Peaking Plant (new efficient peaking plant). Total pot is divided into 12 monthly pots (30 % fixed year ahead, 40% month ahead, 30 % ex-post) (Lawlor, 2012). In contrast to the capacity-based Irish market, the UK electricity market is an energy-only market (capacity auctions planned to be implemented in the future). The BETTA (British Electricity Trading and Transmission Arrangements) model relies heavily on bilateral contracts.

Between Ireland and UK, there are two interconnectors: the Moyle connection and the East-West Interconnection (EWIC), which became operational in September 2012. For the Moyle connection, the explicit auctions are in use for long-term, day-ahead and intraday time-schedule. Use-it-or-sell-it principle is applied for the long-term contracts. Similar trading approach has been planned for the EWIC (National report UK, 2012). Mutual Energy Limited owns and operates the Moyle interconnection and the EWIC is owned and operated by EirGrid. Interconnector users are paid or they pay based on the flow in interconnector (capacity + energy).

The main reason causing inefficiencies between UK and Ireland electricity trading seems to be the ex-post price calculation in the Ireland market. However, the existence of the capacity payments in the Irish market can cause inverse flows with respect to the short price difference between the UK and Irish market. At present, the British electricity exporter has to guess the price level in the Irish market and, based on that, decide whether or not to export electricity from UK to Ireland. The final electricity prices in Ireland are published four days after the delivery day and in some cases the electricity flow is found to have been from high price (UK) area to the low price (Ireland) area.

4.3 Lessons for Europe

The EU target is an internal electricity market, where power exchanges would schedule power flows between regions based on the bids and offers on both exchanges to find a joint market clearing position. Market integration is expected to increase both welfare and the security of supply. At present, however, the single market is still far from being accomplished. Furthermore, to some extent the markets in Europe seem to be fragmenting rather than integrating. For example, numerous Member States are currently considering of moving from energy-only markets towards more capacity-based markets. The discussion about the need for capacity payments in Europe is

facilitated by the high penetration of subsidized RES, which causes revenue inadequacy for the conventional generators. The rationale for the capacity payments seems to be to keep the conventional generators in the markets for the reliability and security of supply reasons by providing them with additional fixed payments to compensate the inadequacy of the revenue streams from the day-ahead electricity markets. However, from the internal market point of view, the re-designing of the national markets is problematic because of the distortions that the capacity payments may cause to the cross-border trade. On the other hand, similar distortions can also be caused by national RES subsidies because they also have distributional effects that can impede trade.

5. Conclusions

In this report, we have presented the results of a research project focusing on the cross-border trade between the Nordic and Russian electricity markets. In addition, we have discussed the characteristics and future prospects of the Russian electricity market. The electricity supply industry in Russia is undergoing a massive investment program that will drive up the total costs of electricity. The demand side is likely to face the higher costs especially in the form of increasing capacity charges. However, at the same time the large amount of new generation entering the market may lead to overcapacity, which might put downward pressure to the day-ahead electricity prices. To some extent, the overcapacity problem may be alleviated by demand growth if it progresses as forecasted.

Uncertainties exist in what will be the shares of capacity and electricity in the total costs of electricity in Russia. Investments in new generation are the primary driver of the capacity costs. For the electricity price, the domestic gas price is an extremely important price driver. For example, according to our modelling results, if the gas price increases annually by 15% during the next few years (which has been the official plan until recently), the electricity prices in the North-West Russia may increase by 10-15€/MWh by 2016. The gas-fired power plants constitute almost 65% of the total installed electricity generation capacity in the North-West Russia. The question of the domestic gas price development is essentially a political one.

The current capacity market rules in Russia hinder the cross-border electricity trade between the Nordic and Russian markets. The reason is that during certain daytime hours on weekdays, the cross-border trader has incentives to reduce export to avoid capacity costs. We can see limited cross-border flows during specific peak hours, when the trader is subject to capacity charges. Even though the electricity price spread (the difference between electricity prices in markets) would justify the cross-border trade, the capacity payments may prevent it, creating a so-called “dead band” or price interval when it is not rational to transmit electricity between two markets. This leads to inefficient use of the interconnector capacity between the two markets. The technical reconstruction of the interconnector to enable bidirectional trade across the interconnector would not eliminate the capacity payment related inefficiencies in the cross-border trade. Most of the time the flow would still tend towards Finland and the existing barriers to trade would continue to hold.

To increase trade, the optimal cross-border flow could be defined on the basis of the price difference in the day-ahead markets (i.e. through market coupling), in which case the capacity payments would not create a barrier to trade. The result would be more efficient utilization of the interconnector. However, problematic distributional effects could arise if consumers in the energy-only market were considered to benefit at the expense of the consumers in the capacity-based market. For example, the capacity payments may lower the day-ahead electricity prices (e.g. if the generators bid differently to the day-ahead markets because the day-ahead market revenues alone no longer have to cover their total long-run going-forward costs but part of the revenues comes through the fixed capacity payments). In such case, the consumers in the neighboring energy-only market would benefit from the lower day-ahead electricity price without having to take part in ‘subsidizing’ the generators in the capacity-based market. Attempts to allocate part of the capacity costs to the consumers in the neighboring energy-only market are likely to give rise to questions

about the distributional effects such as: “Why should the consumers in the energy-only market subsidize firm capacity in the neighboring country?”

Having an energy-only market on one side of the interconnector and a capacity-based market on the other side often causes an inefficient use of the interconnector. Ignoring the capacity mechanisms in the cross-border trade could solve the problem in theory but might be problematic to implement in practice because of the aforementioned distributional effects. However, the diversified generation mixes in the Nordic and Russian market would seem to justify pursuing the economic benefits of trade between the two markets despite of the differences in the market designs. Enhancing the possibilities of trade would require technical reconstruction of the interconnector between Finland and Russia to enable bidirectional flow between the two markets (instead of the current unidirectional flow only from Russia to Finland). The reconstruction of the interconnector may be feasible if the benefits (i.e. the welfare gains of introducing bidirectional trade) are higher than the costs of reconstruction.

In our example calculations we analyzed the prospects of cross-border trade under different trade arrangements between two markets that resembled the Finnish price area of the Nordic market and the North-West zone of free power flow of the Russian market. In the base scenario, we assumed that only unidirectional electricity flow between the markets was possible and that the cross-border trader acted as a monopolist. According to the modeling results, the introduction of market coupling would increase trade and bring welfare benefits to both markets. In total, market coupling would lead to about four times higher energy flow than what is observed in the base scenario (i.e. from about 2,3 TWh annual energy flow in the base scenario to about 9,3 TWh when market coupling is used). In our simplified example calculations, the benefits of market coupling in comparison to the base scenario could be around 60 million Euros annually. Assuming investment costs of 160 million Euros (here we refer to the estimated costs of a DC link between Lithuania and Poland), a 15% discount rate, and a 20 year payback period, we get a 25 million Euros annuity for the project of reconstructing interconnector. With these assumptions, the higher annual benefits compared to the costs of the project could justify the reconstruction of the link. However, if we assumed a monopolistic cross-border trade arrangement instead of market coupling and imposed capacity payments on the cross-border trade, our example calculations would suggest a different conclusion.

6. References

ATS. Capacity availability factors Available: https://www.atsenergo.ru/reporting/public/eur/MFORM_coeff_fact_nalich/

ATS, 2012a. List of forced generators for 2012. Available: https://www.atsenergo.ru/reporting/public/eur/MFORM_sale_volume_VR_zsp/20121201

ATS, 2012b. Methodology of calculation of capacity prices for consumers.

CER, 2011. CER Factsheet on the Single Electricity Market. Commission for Energy Regulator. April 2011. Online: <http://www.cer.ie/en/information-centre-newsletters.aspx> [Dec 11, 2012].

Gore O., Viljainen S., Makkonen M., Kuleshov D. Russian electricity market reform: Deregulation or re-regulation? Energy Policy 41, 676-685 (2012).

Lawlor, J. 2012. The SEM Capacity Payment Mechanism and the impact on trade between Ireland and GB. Market Design Seminar, Stockholm, 2012. Online: <http://srv128.bluerange.se/Programomraden/Anvandning/MarketDesign/Events/Seminars1/2012-Capacity-markets/> [Dec 11, 2012].

Littlechild, S., 2006, "Foreword: The Market versus Regulation", in Electricity *Market Reform An International Perspective*, Sioshansi F. P., Pfaffenberger W. (Eds.). Elsevier, pp. xvii-xxix.

Ministry of Energy of Russia, 2013. Scheme of the development of the Russian power sector 2013-2019. Government Decree N309 on June 19, 2013.

MISO, 2011. MISO/PJM Interchange Transaction Optimization Overview. Joint Stakeholder Meeting, Oct 7, 2011. Online: http://www.pjm.com/committees-and-groups/stakeholder-meetings/stakeholder-groups/pjm-miso-interchange.aspx [Oct 31, 2012]

MISO, 2012. MISO and PJM Day-Ahead Market Coordination Efforts. SMWG. Feb 27, 2012. Online: https://www.midwestiso.org/Events/Pages/SMWG20120227.aspx [Oct 31, 2012]

National report Ireland. 2011. ERGEG. Online: <http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202011> [Dec 4, 2012]

National Report UK. 2012. ERGEG. Online: <http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202012> [Dec 11, 2012].

Regulation 13. Determination of the actual capacity delivered to capacity market. November 26, 2010.

Regulation 13.2. Determination of capacity buy and sell volumes. August 30, 2010.

Regulation 19.3. Competitive capacity auction procedure.

Russian government, 2010a. General plan for the development of the power sector in Russia 2030.

Russian government, 2010b. The performance and price parameters of long-term capacity market. Government Decree N89 on February 24, 2010.

Russian government, 2010c. Lists of generators under Capacity Delivery Agreements. Government decree N1134, August2010.

System Operator, 2012. Results of competitive capacity auctions on 2012. Report on November 11, 2011.

SO-UPS Russia, 2012. Planned monthly peak hours. JC System Operator. Available online: <http://www.so-ups.ru/fileadmin/files/company/markets/pik_chas2012.pdf> (In Russian).

The Brattle Group. 2011. Preliminary Issue Description. MISO-PJM Capacity Market Seam. [Dec 11, 2012].