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Essays on the Russian Electricity and Capacity Market

Essays om det russiske elektrisitets- og kapasitetsmarked

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To my family

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Igor Pipkin
Ås, January 2016

SUMMARY

During the past decade the Russian power sector has undergone a dramatic reform. This has created a need for better understanding of the drivers and development of the sector. This dissertation describes the functioning of the Russian power market since 2006 by focusing on price formation, market power and the main regulatory obstacles for competition.

Paper I focuses on time regularities in Russian power prices and compares these for the Siberian and the European zones. A set of distinct time regularities is revealed and discussed: “Day-of-the-week pattern”, “Weekend pattern” and “Time-of-the-day pattern”. The magnitudes of the price differences and time lag between the zones raise the question of extending the interconnectors between the zones. The persistence and magnitude of time regularities in power prices in the European zone imply that technologies that allow for flexibility, either on the supply or demand side, can be profitable.

Paper II tests for market power in Northwest Russia using the Bresnahan–Lau framework by estimating residual demand and supply curves for thermal producers. I find that price mark-ups are close to 7–8% on average for the hours between 10 am and 9 pm and 2–3% for the remaining hours of the day. The residual demand curve elasticity is relatively high during peak hours. In addition, demand from Finland/Baltic states and Center FFZ24 have different profiles, such that total demand is most elastic during peak hours and least elastic during the periods of rapid change in consumption. The increase in natural gas prices was reflected directly in electricity prices in Northwest Russia in the analysed period. The domestic prices for natural gas are expected to increase to the level of European net-back prices, and given that natural gas will still be the main fuel in electricity production, this price increase will also be reflected in electricity prices.

The objective of Paper III is to take into account the mathematical formulation of the Russian power market in the calculation of concentration measures and investigate the role of transmission constraints using the more detailed framework of the transmission constrained residual supply index (TCRSI). The analysis supports the previous findings of high market concentration in the Russian power market, but for different reasons. The adjusted HHI is below 1400 on average for all price zones and UESs and the adjusted RSI shows that there exist pivotal generators for more than 5% of hours in the analysed period only in two of 21 free-flow zones. Nevertheless, the TCRSI reveals that market

concentration is critical for most FFZs in Russia in the UC auctions, day-ahead (DAM) and capacity markets. Market concentration decreases the higher is the share of hydro producers and transmission capacity to the neighbouring regions in the Russian power market in general and in addition depends on the share of fixed generation in the DAM.

Paper IV investigates the main challenges and obstacles to competition in the Russian power market, especially regarding the role of the SO. The transmission constraints between the European and Siberian zones forced by the SO led to enormous subsidization of the Siberian zone by customers in the European zone in the DAM. In addition, must-run generation forced by the system security constraint and demand for heat affects competition in the capacity market and the UC auctions, which lead to distortions of DAM. The linear demand curve for capacity by price zone provides incentives to exert market power, price cap constraints the potential profits of generators, whereas the lower bound given by the total installed capacity reduces the incentives for competition.

On the basis of these findings, I present the following policy recommendations: facilitate consumer response to variation in electricity and capacity prices and invest in flexible technology on supply or demand side; upgrade the existing transmission capacity to discourage the exercise of market power and to deal with the supply security concerns; introduce competitive pricing of heat and fuel (natural gas and coal).

CONTENTS

LIST OF ACRONYMS

AO	Russian acronym for Joint Stock Company
ATS	Trading System Administrator (atsenergo.ru)
CHP	Combined heat and power
DAM	Day-ahead market
EMPS	Multi area power-market simulator
FAS	Federal Antimonopoly Service (en.fas.gov.ru)
FFZ	Free flow zone
FGC	Federal Grid Company (fsk-ees.ru)
FST	Federal Tariff Services (fstrf.ru)
GDP	Gross Domestic Product
GMM	Generalized Method of Moments
HAC	Heteroskedasticity and autocorrelation consistent
HHI	Herfindahl-Hirschman index
IEA	International Energy Agency
IPS	Integrated Power System
LI	Lerner Index
LMP	Locational Marginal Price
LRMC	Long-run marginal cost
LTA	Lont-term (capacity) aggrement
MC	Marginal cost
MOSENEX	Moscow Energy Exchange
MR	Marginal revenue
MVA	Mega Volt-ampere
MW	Megawatt
OGK	Wholesale Power Market Generating Company
OPF	Optimal Power Flow
PCMU	Price-cost mark-up
PJM	Pennsylvania-New Jersey-Maryland wholesale electricity market
RAO	Russian Open Joint Stock Company
RDI	Real Disposable Income
RSI	Residual Supply Index
RUB	Russian ruble
SO	System Operator (so-ups.ru and br.so-ups.ru)
TCRSI	Transmission-constrained Residual Supply Index
TGK	Territorial generating company
UC	Unit Commitment
UES	Unified Energy System
UPS	Unified Power System of Russia

Introduction

Russian Power Market Reform and Current Developments: Policy and Research Issues

1 Introduction

During the last 30 years, most developed countries have undertaken comprehensive privatization, restructuring and deregulation programs in sectors that were previously regulated monopolies or state owned. Examples include airlines, trucking, telecommunications, natural gas, mail, railroads, and others (Joskow 2008). The liberalization and restructuring of the power sector began in Chile in the early 1980s and continued in Argentina and other Latin American nations with limited success, until the UK Government privatized the UK electricity market in 1990. This was followed by deregulation of markets in the Nordic countries, Australia, New Zealand, Japan, and regional markets such as Alberta, Texas, California and PJM. Comprehensive electricity sector liberalization principles now apply to all EU countries.

The Russian electricity reform is well-documented by both Western and Russian researchers (Cooke 2005; Pittman 2007; Palamarchuk et al. 2008; Abdurafikov 2009; Solanko 2011; Pogrebnyak 2007), but there are still very few empirical studies on the Russian power market. This dissertation adds to the empirical research on the Russian power market by focusing on price formation, market power and the main regulatory obstacles for competition. The dissertation consists of an introductory chapter and four independent papers.

Market liberalization is a process rather than an event, and analysing developments in the longest-running liberalized markets reveals various phases that are likely to be part of the liberalization process (Stridbaek 2005). Russia's society and economy has experienced dramatic changes since the collapse of the Soviet Union. This has also shaped the process of one of the most ambitious electricity reforms ever undertaken, namely liberalizing a one-thousand TWh power market. This introductory chapter begins with a description of the Russian economy and electricity sector prior to deregulation, and continues by describing the market mechanisms introduced by the reform in the second section. The third section highlights the important remaining challenges and issues of concern. The final part focuses on the contribution of the dissertation and main conclusions.

2 RUSSIA PRIOR TO THE ELECTRICITY REFORM

After the collapse of the Soviet Union, the Russian economy experienced a number of important reforms. Most price controls were removed and both domestic and foreign trade were liberalized (Shleifer and Treisman 2001). As a result, exports increased by 30% from 1992 to 1997. In addition, markets for corporate shares, government bonds and stocks were developed. One of the main arguments for privatization and liquidation of economic governance structures in the USSR were excessively large enterprises, as well as monopolization and centralization in the Soviet economy (Volkonskiy 2002).

The liberalization solved the problem of a shortage of goods in the late 1980s, but the Russian economy became even more dependent on natural resources (oil and gas) during the 1990s. According to the Federal State Statistics Service, real disposable income (RDI) and gross domestic product (GDP) decreased steadily during the 1990s (see Figure 2.1). These declines occurred at the same time as an increase in the mortality rate of 40%, a decrease in the birth rate of 60%, and an increase in the number of serious crimes of 350%.

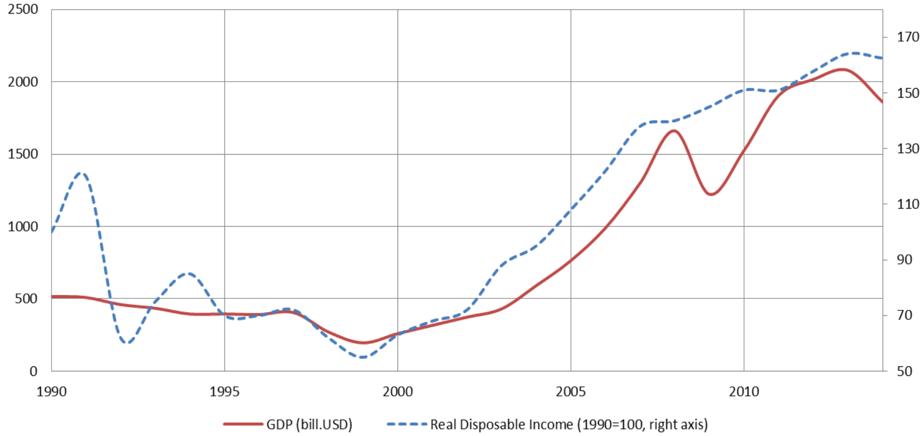

Figure 2.1 GDP and RDI in Russia (World Bank)

In order to lower inflation, energy prices in Russia remained heavily and unevenly subsidized (Shleifer and Treisman 2001). Gazprom committed to sell natural gas to domestic customers under tariffs regulated by the Federal Tariff Service (FST) in exchange for unique rights to export natural gas from Russia. The dominance of Gazprom, and the challenges and obstacles of liberalization of the natural gas market in Russia, are well-described by Tsygankova (2010). The oil and coal sectors are deregulated, but have few market participants and close links to the government. Coal export volumes are still regulated by the Ministry of Energy of the Russian Federation (Minenergo).

Prior to deregulation, the Russian electricity sector was a vertically integrated monopoly, RAO UES[1], regulated by the FST. This entity suffered from non-payments from both private and government organizations, which partially explains the underinvestment in maintenance and new infrastructure during the 1990s. The holding company owned 72% of installed generation[2], 96% of transmission and distribution capacity, and employed a staff of more than 400 000 people in 2004. RAO UES's shares were quoted on most stock exchanges in Russia, and were among the most liquid securities[3].

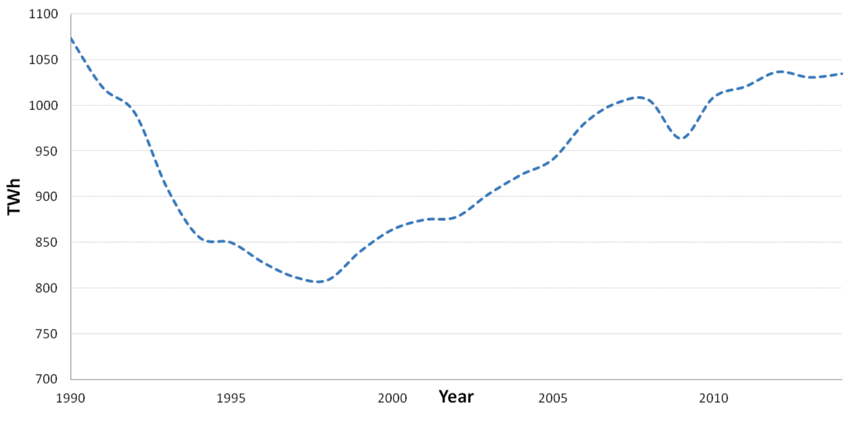

Figure 2.2 Electricity consumption in Russia (World Bank)

[1] RAO UES is used as the company name, and refers to the electric energy holding company "Unified Energy System of Russia" established by Presidential Decree #932 in August 1992.
[2] RosEnergoAtom owned and still owns all nuclear generation in Russia.
[3] Foreign legal entities owned 34.3%, Russian legal entities owned 5% and individuals owned 8.2% of RAO UES shares in 2000, whereas the Russian Government owned the remaining 52.5%.

The main advantage of a monopoly utility model is that, in theory, all the components of the system can be coordinated to achieve least-cost of operation in the short term. In the long term, maintenance and the development of the transmission capacity and topology with the introduction of new generation capacity can be synchronized. On the other hand, theory predicts that profit-maximizing firms will take better care of their plants and will have different expectations and forecasts of the future, whereas central planners tend to overestimate the need for new generation capacity (Kirschen and Strbac 2004).

The collapse of the USSR resulted in an economic downturn and a decrease in annual electricity consumption from over 1000 TWh in 1991 to 800 TWh in 1998, as illustrated in Figure 2.2. RAO UES made few investments in infrastructure during those years (Palamarchuk et al. 2001). Thus, at the beginning of the 21st century, Russia faced ageing generation and transmission infrastructure, poor technological efficiency, and consequently, had an enormous need for investments in the electricity sector to ensure growth in the economy. As illustrated in Figure 2.3, the installed generation and transmission capacity is far from modern.

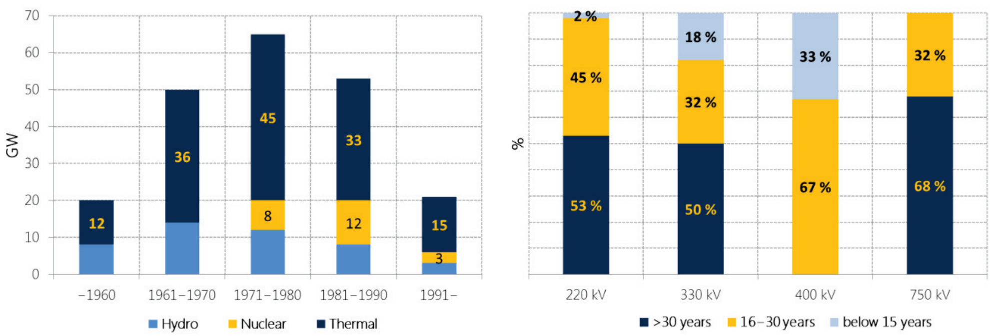

Figure 2.3 Installed generation and transmission capacity by age (APBE[4], 2007)

The Russian power industry has always been considered as the “engine” for economic growth and development, which explains the main goals for the electricity reform defined in Russian Federation Government Resolution #526 (GR-2001):

- to ensure resources and infrastructure for economic growth
- to improve the competitiveness of the Russian economy in the international market
- to ensure the energy security of the state and prevent a possible energy crisis.

[4] The Agency for Energy Balance Forecasting (APBE) (http://www.e-apbe.ru/).

The electricity reform officially commenced on 26 March 2003 when the necessary legislative documents were signed to launch the process of splitting RAO UES into private generation and supply companies that could compete on the wholesale market. The government retained control of the Federal Grid Company (FGC), the System Operator (SO), and the nuclear (RosEnegoAtom) and hydro (RusHydro) generation companies. Meanwhile, the main objectives of the electricity reform were defined in Federal Law #35 "On Electricity" (FL-2003) as follows:

- to create competitive markets in all regions in Russia, where technically possible
- to create an effective mechanism to decrease costs in generation, transmission and distribution
- to promote energy savings/efficiency in all sectors of the Russian economy
- to create favourable conditions for new investments and the operation of new generation and transmission infrastructure
- to improve the financial parameters of the sector in general
- to eliminate in a stepwise manner the cross-subsidization of different regions and groups of consumers
- to preserve and develop a unified electricity infrastructure system, including transmission and dispatch management
- to demonopolize fuel markets for thermal power plants
- to create a regulatory and legal framework for reforming the sector within the context of the new economy
- to reform the system of state regulation, control and supervision in the power industry.

This ambitious list of objectives for the electricity reform includes socioeconomic aspects such as subsidies, liberalization of natural gas and heat markets, increased attractiveness of the sector for new investments, etc., which implies the stepwise introduction of market mechanisms.

3 THE RUSSIAN ELECTRICITY AND CAPACITY MARKET

The Russian Day-ahead Market (DAM) was launched in 2006, and large generators (above 25 MW), export/import operators (InterRAO), large consumers (above 20–25 MVA), sales companies and guaranteeing suppliers were obligated to participate. The Administrator of the Trading System (ATS) is responsible for collecting the bids and offers, and running the clearing mechanism based on the description of the system from the SO[5]. While participation in the DAM is mandatory, only 10% of electricity was traded in auctions in 2006. The remainder of the market, including the residential sector, had all tariffs imposed by the FST. The electricity traded in the DAM increased gradually to approximately 80–90% of total market demand by 2011. In contrast, the residential sector still receives the FST tariff[6]. The tariff is calculated based on forecasts of social and economic development of the Russian Federation, and approved by the Government of the Russian Federation. The FST sets the minimum and maximum tariffs for electricity and capacity on a monthly basis.

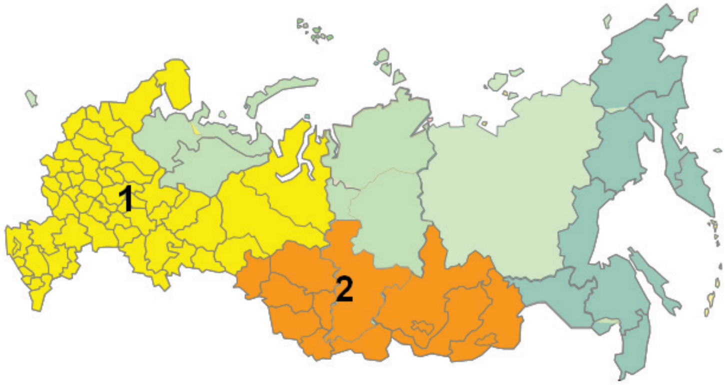

Figure 3.1 European (1) and Siberian (2) price zones and non-price zones[7]

Russia is divided into the European and Siberian price zones, as illustrated in Figure 3.1. The remaining regions are non-price zones or isolated areas, where competition is not possible. All customers in non-price zones, except the residential sector, receive FST tariffs calculated based on the price in the DAM. The SO manages all business processes necessary for a functioning market for electricity and capacity in the non-price zones, excluding competitive auctions, because the price is regulated.

The Siberian price zone consists of only one Unified Energy System (UES) Siberia, whereas the European zone includes UES Ural, UES Volga, UES South, UES Center and UES Northwest.

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5 ATS runs the Security-Constrained Optimal Power Flow model to determine nodal prices based on the topology including transmission constraints from SO.
6 The guaranteeing suppliers (see section 3.7 for definition) in some subsidized federal subjects (oblast), including North Caucasus, Tuva Republic and Republic Buryatia, also receive the FST tariff.
7 Non-price zones is term translated directly from Russian – "неценовые зоны", but is the same as zones with regulated prices.

Figure 3.2 illustrates the relationship between UES and free-flow zones (FFZs). The UES conglomerate consists of regional energy-systems, and the borders are based on the grid rather than on federal subjects (oblast). Similarly, FFZs are defined by the SO based on the transmission constraints calculated in a security-constrained power flow model, and thus ignore energo-systems or any administrative definitions. Formally, the SO ignores the UES when defining the FFZ, but for simplicity we assume that UES consists of many FFZs, as illustrated in Figure 3.2.

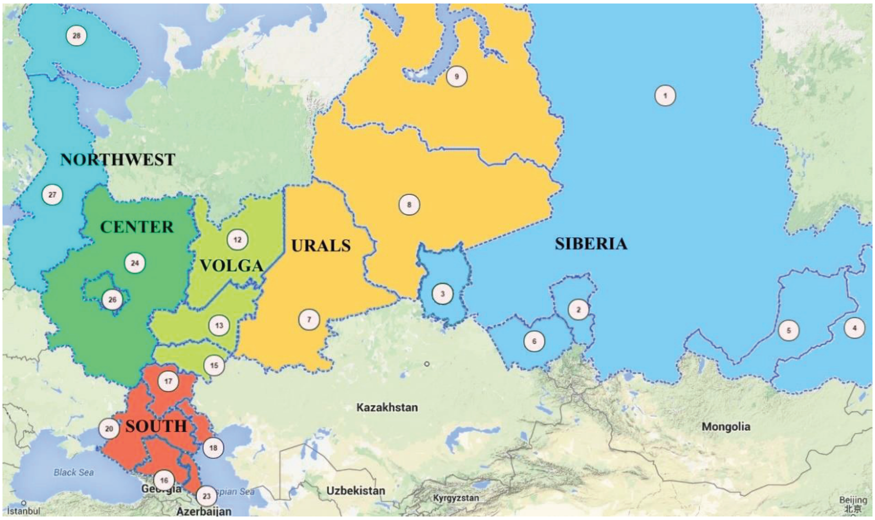

Figure 3.2 UES and FFZ in the Russian power system

Notes: UES Siberia (Siberia-1, Kuzbass-2, Omsk-3, Chita-4, Buryatiya-5 and Altay-6), UES Ural (Ural-7, Tyumen-8, North Tyumen-9), UES Volga (Vyatka-12, Volga-13 and Balakovo-15), UES South (Kavkaz-16, Volgograd-17, Kaspiy-18, Kuban-20 and Mahachkala-23), UES Center (Center-24 and Moscow-26) and UES Northwest (West-27 and Kolskaya-28).

Average hourly consumption/load was 28.4 GW in UES Ural, 25.3 GW in UES Center and 22.6 GW in UES Siberia in the period from January 2012 to July 2015. More than half of Russia's hydro generation is installed in Siberia, but hydro generation also represents a significant share of generation in UES South and UES Volga. The nuclear generators are located west of the Ural Mountains, primarily in UES Center, UES Northwest and UES Volga. The smaller FFZs in Siberia depend mostly on FFZ1 Siberia, whereas FFZ8 Tyumen contributes to FFZ9 North Tyumen. Similarly, power flows primarily from FFZ28 Kolskaya to FFZ27 West in UES Northwest, which either exports power to the Baltics and Finland or to UES Center.

3.1 The Day-ahead Market

The clearing mechanism of the market is an optimization problem, consisting of an objective function and constraints with certain characteristics. The Russian Day-ahead Market is formulated by maximizing social welfare in a security-constrained optimal power flow problem (SC-OPF), i.e. including formalization of active and reactive power flows[8], a balance constraint on active and reactive power, constraints on active power flows through sections (predefined number of power lines), ramp-up/down constraints, and minimum and maximum generation. In addition, an integral constraint for generation in a 24-hour period is applied to thermal and hydro generators if daily fuel/water consumption is constrained. Thermal and nuclear generators are allowed to bid three pairs of prices and volumes above minimum and below maximum generation (pmin/pmax)[9], which are defined by the technical characteristics of the generation units or by the SO in unit commitment (UC) auctions based on the security constraints.

ATS solves the SC-OPF problem for approximately 8000 nodes[10] and 12 000 power lines and for all 24 hours of the day, subject to the balancing constraint, maximum/minimum constraints on generation and flows, the integral constraint and ramp-up/down constraints on generation. Nodal prices are dual values on the balancing constraint, including shadow prices on transmission and prices of losses. The objective function and the main constraints are presented in Paper 3 in Appendix 2 Model 1 or see Davidson et al. (2009) for more details. The nodal prices or locational marginal prices (LMPs) are the marginal prices, which are price sensitivities that are produced at the solution of the optimization problem. Price smoothing in the ATS clearing mechanism ensures that only generator offers can clear the market and that nodal prices are non-negative[11]. The price at node i consists of the marginal cost of meeting total demand at the reference bus j (price of energy), marginal cost of transmission losses (thermal losses in the transmission lines from reference bus j to bus i) and marginal cost of transmission congestion (from reference bus j to bus i) because of binding constraints, e.g. binding transmission line

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8 Active and reactive power flows are defined as non-linear equations incorporating Kirchhoff's circuit laws.

9 Formally, this comprises six bids, where three bids are with volumes below pmin and price close to zero, and three bids are significantly above zero and volume above pmin. The market algorithm will correct the bids if these are specified incorrectly, whereas the clearing algorithm in practice will set prices at zero for all bids below the minimum generation constraint (pmin).

10 The actual number of nodes changes because of maintenance of the grid, availability of power plants, etc. ATS publishes monthly reports with updates of the list of nodes in the topology.

11 This is common for the DAM, UC auction and the capacity market.

constraints (Litvinov et al. 2004). See Zimmerman et al. (2009) and Zimmerman (2010) for more on the mathematical formulation and solutions for AC OPF problems.

The ATS publishes nodal prices for the largest 5000 nodes in addition to the sell/buy price indexes for the FFZ, UES and price zones, which are volume-weighted averages of nodal prices at the generation/consumption nodes in each area. The sell and buy indexes differ on average mainly because of the distribution of loss costs between generation and consumption. For simplicity, we refer to the average of the sell and buy indexes as the price in the region (FFZ/UES/price zone).

3.2 The UC auction

The SO runs three-days-ahead security-constrained (N-1) OPF UC auctions, where in addition to the DAM optimization problem one has to take into account reserves, i.e. start/stop costs, to meet expected demand and reduce total costs for the system. The UC auction was initially a seven days-ahead auction, but in June 2014 the schedule was reduced to three days-ahead. The participating generators offer both generation price–volume pairs and start/stop costs. The dual values in the UC auctions represent total costs of meeting demand at each node and necessary reserves, including start/stop costs and security constraints, in addition to the constraints from the ATS clearing mechanism described above. The minimum and maximum constraints for generation are based on the technical characteristics of the generators and technology. The generator constraints in the DAM are set based on the solution of the UC auction, whereas offers submitted in the UC auction are used as price caps for the offers submitted by these generators in the DAM. See Davidson and Seleznev (2014) for more details on UC auctions.

In a system dominated by thermal power plants, start/stop costs can represent a significant share of total costs. The UC auction identifies which plants need to start, and start costs are collected from the consumers outside the market, based on the geographical distribution and deviations in consumption profiles from average load. The regime units (system security reasons) and must-run units (for example, heat demand) have priority in determining running status, i.e. these units receive “on” status despite high offers (for start-up) that avoid competition. Notice that the SO estimates the consumption for the three days ahead, and consumers do not take part in the auction directly.

3.3 THE BALANCING MARKET

The balancing market is a market for deviations from the schedule formed in the DAM (i.e. after the DAM has closed) in which the SO acts to ensure demand equals supply, in and near real time. Consequently, the supply offers and demand bids from the DAM form maximum/minimum offers/bids in the balancing market. Market participants are generators and large consumers with flexible load. The clearing mechanism is based on the SC-OPF problem given the real-time topology and system description. The generators can offer a decrease or increase in load compared with planned volumes in the DAM. Offers of a decrease in load from large industrial consumers are treated the same way as offers of an increase in load from generators. Market participants who adjust their load following instructions from the SO receive a "better" price, whereas all deviations by own initiative receive a lower/higher price compared with the solution from the DAM for generation/consumption, respectively.

3.4 THE MARKET FOR SYSTEM SERVICES

The Integrated Power System (IPS) is a wide-area synchronous transmission grid, comprising most of the countries in the former Soviet Union, excluding the Baltic countries. The Russian portion of the IPS is referred to as the Unified Power System of Russia (UPS), which is now operated by the Federal Grid Company (FGC). The SO is responsible for system security, reliability and quality.

The market for system services, operated by the SO, motivates generators to invest in the modernization of power plants and the introduction of modern process control systems. The legislative documents do not use the term "market" as such, but instead use terms such as "auctions", which can be competitive based on the offers, or non-competitive and regulated by other principles (Rychkov 2010). In the second half of 2015 there are 10 companies (one hydro and 62 thermal generation blocks) that provide primary frequency control, and seven companies participate in the reactive power control.

3.5 THE CAPACITY MARKET

By the end of the first decade of the 21st century, the Russian electricity sector faced enormous investment challenges given ambitious economic growth expectations and the average age of the generation and transmission infrastructure. Thus, the primary goal for the capacity market is to attract and stimulate investments in generation, reduce peak consumption, cover fixed costs for generation and reserves.

The capacity market was introduced in 2010 and the competitive capacity charges were passed over to end-users, which led to end-user price increases of 30–40% (Gore et al. 2012). The intent of the capacity market is to compensate marginal producers for the “missing money” problem[12] that has discouraged efficiently timed and sized generation investment in several IEA markets (Cooke, Antonyuk and Murray 2012). Insufficient incentives for investment in electricity generation are discussed further in Joskow (2006) and Joskow (2008b).

The capacity mechanism in Russia consists of two elements: long-term capacity agreements (LTAs) and the annual capacity auction. The LTAs were a binding investment obligation on all parties that purchased or controlled generating assets following the privatization process. LTAs guaranteed a 13–14% return on investment[13], reducing investors’ capital risk by enabling them to recover most of their capital within the first 15 years of operation (Cooke 2013). LTAs are included in the annual capacity with price-accepting offers, but receive a separate tariff defined by the Ministry of Energy and Federal Tariff Service and paid by the customers within a FFZ. All delays in commissioning new capacity through LTAs are penalized by the Ministry of Energy and the SO. According to Cooke et al. (2012), new investment requirements are already secured to 2020 through the LTA mechanism.

The annual capacity auction is thus an auction for residual demand for capacity, corrected for the capacity introduced through the LTAs for the following year. The auction is cleared through zonal pricing based on FFZs defined by the SO as zones without major transmission constraints within the zone. Based on the peak demand forecast, the information about available capacity[14] and description of the grid, the SO also calculates constraints for the exchange between FFZs and clears the market based on the offers from generators. The SO defines peak hours *ex ante* for every month of the following year. The final bill for the consumers is calculated as an average of maximum consumption during peak hours in the previous month.

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[12] The marginal generator will cover only marginal costs in a competitive market.
[13] The average inflation rate was 8–14% in 2005–2009 and 8–10% in 2010–2014.
[14] This refers to commissioning capacity during the year and maintenance of existing generation.

The Federal Antimonopoly Services (FAS) has been active in setting price-caps on the annual capacity auctions in most of the FFZs, because of the dominant positions of a few large generators who could exert market power due to poor transmission capacity between the zones. Thus, the competitive capacity price existed only for 2–3 FFZs, which have led to discussions about other formulations of the capacity auctions. Recent increases in installed capacity through the introduction of new generation LTAs and delays in the decommissioning of old power plants, in addition to decreases in consumption because of the political situation, have led to discussions on introducing elastic demand for capacity. The demand function will be a linear function regulated by the Ministry of Energy and the SO from August 2015. In addition, the capacity market will be cleared based on price zones rather than the FFZs, taking into account the transmission congestion inside the zones for reserve requirements.

3.6 THE MARKET FOR ELECTRICITY AND CAPACITY DERIVATIVES

The financial market, represented by Moscow Energy Exchange (MOSENEX), accommodates bilateral trading in capacity and electricity month-ahead contracts and monthly futures for electricity. Month-ahead futures on the hub price[15] have traded consistently since the launch of the exchange, but the traded volumes represent only a small fraction of the physical market. The interest in bilateral capacity contracts has been modest since the launch in 2011, and so far (May 2015), no trades have been registered in 2015 on MOSENEX and nor have there been any bilateral contracts for energy since January 2014. The maximum monthly trading volume has not exceeded 250 million RUB since May 2014, and since September 2014 the turnover has fallen to below 50 million RUB per month or some 2–8% of the DAM spot market.

3.7 THE RETAIL MARKET

Kuleshov et al. (2012) state that the retail market is divided into inactive and sub-active markets. The social importance of the affordability of electricity supply plays an important role in the analysis of retail electricity regulation. Boute (2015) identifies three reasons for poor competition in the retail market for electricity in Russia:

[15] The hub is defined as the number of nodes with a high correlation between nodal prices and small differences in absolute values, see www.mosenex.ru/eng.

- competition and the introduction of a free market is not an option because of economic and/or technical reasons
- political sensitivity in relation to access to energy in Russia
- regulation of prices charged by guaranteeing suppliers is a way to address the risk related to the dominant position of these companies in the Russian retail market.

Guaranteeing suppliers were formed based on the former AO-Energos, the entities in charge of retail supply prior to liberalization (Svirkov 2006). Guaranteeing suppliers act as intermediaries between producers and household consumers purchasing electricity in the wholesale market at prices set by the FST, and resell this electricity at regulated prices to the residential sector. The prices to all other customers are calculated based on average wholesale prices.

The Russian Government plans to stimulate competition in the retail market by deregulating the electricity supply to residential consumers and reducing the market share of the guaranteeing suppliers (Boute 2015). The limited role of liberalization in retail markets is not a major problem as long as regulated prices reflect the real cost of production, i.e. reflect the wholesale price of electricity and capacity, transmission and distribution costs (Joskow, 2008). The remaining part of this introduction and thesis will focus only on the Russian wholesale market for electricity and capacity.

3.8 REGULATORS

The use of the phrase "deregulation" to characterize the attributes of the most successful electricity sector reform programs is misleading (Joskow 2008). The regulation must remain, given the significance of the electricity sector for society and economic development, but the nature of the regulation evolves in parallel with the liberalization process. The security of supply in the short term implies balancing supply and demand for electricity at a certain time synchronously in the system. On the other hand, supply adequacy is a long-term phenomenon, which traditionally has been subject to central planning in Russia. Another factor is diversification of the fuel mix and security of supply in fuel markets, such as natural gas and coal. The list of regulators in the electricity sector is presented in Table 3.1.

During the first decade of the century, the Ministry of Energy of the Russian Federation published "*Energy Strategy until 2020"* (adopted in 2003) and later "*Energy Strategy until 2030"* (2008), focusing on energy policy including electricity, coal, natural gas, and oil and the corresponding "*General Scheme for the Installation of Electricity Facilities until the year 2030"* (2010). In practice, these documents specified the list of sites and regions to install generation and network facilities to provide a reliable supply of electricity and heat to support the development of the Russian economy.

The LTA mechanism solves the issue of supply adequacy, while the capacity market allows for recovery of fixed costs for existing power plants. The long-term capacity auctions, which can be initiated by the Ministry of Energy if necessary, will substitute 5-year investment programmes in The General Scheme.

Table 3.1 Major regulators of the Russian power market

Ministry of Energy	Define energy policy, enact legal regulation, manage public property, determine standards
Ministry of Natural Resources and Environment	Supervise environmental issues
Ministry of Transport	Regulate water levels in the large rivers used for transportation
Federal Engineering Supervision Service	Supervise technical specifications of the power plants and grid
Federal Antimonopoly Service	Ensure non-discriminatory access, mitigate market power, define areas with poor competition for the capacity market
Federal Tariff Service	Regulate tariffs; defines price caps for areas with poor competition in the capacity market
Market Council	Form and propose regulatory framework

The role of the FAS and FST has been mentioned in previous sections, and the two organizations will merge during 2015. The primary role of the FST is to calculate the rate of tariff adjustment based on the socioeconomic development in Russia, forecasted by the Ministry of Economic Development of the Russian Federation.

Both the ATS and the Market Council are obligated to report cases of suspicion of market power abuse to the FAS. Most cases are related to market entrance (i.e. grid issues), but price manipulation cases in the DAM, both from generators and consumers, have also been pursued by the FAS.

The Market Council is a non-profit partnership between the market participants (both generators and consumers), to stimulate the implementation of a functioning market. The primary responsibility of the Market Council is the revision of the Wholesale Market Trading System Accession Contract including 27 attachments, which describes the market rules in details. The contract has been revised 92 times from July 2006 to June 2015.

The Market Council is also active in proposing changes to UC auctions and proposing new rules for the capacity market for the 2016 auction. Russian policy makers are being encouraged to position the wholesale market for a move to an energy-only model in the longer term, once these key pre-conditions have been met (Cooke 2013).

4 Issues of concern

Ryapin (2013) characterizes the reform as successful in terms of creating a competitive wholesale market for electricity and capacity, and solving the issues associated with generation capacity. Nevertheless, according to Knyagin et al. (2014), the grid tariffs are improperly high, the sector still suffers from cross-subsidies, and ad hoc state interventions in the market increase the unpredictability and reduce the efficiency of the electric power sector. The Institute of Natural Monopolies (IPEM 2013) has criticized the reform over enormous price increases for final consumers, where those who can, choose to invest in local generation to avoid market and grid tariffs. We will focus solely on the wholesale market in the discussion of issues of concern in the Russian power market.

4.1 RISK MANAGEMENT

Financial risk management is a major priority in liberalized power markets because of substantial price and volume risk. Market participants face risks such as weather shocks, sudden failures in power generation or transmission, the potential for congestion because of unforeseen events, the availability of resources for run-of- the-river hydroelectricity, etc. The Russian electricity sector also faces significant political, regulatory and economic risks.

As previously mentioned, the futures trading volumes on the Moscow Energy Exchange only correspond to 2–5% of the volumes traded in the DAM. The free bilateral contracts on the delivery of electricity at a certain node do not have any direct impact on the DAM for the two participants involved, but constitute a purely financial hedge between the two parties. Free bilateral contracts represent barely 1% of the volumes traded in the DAM in the European zone, and up to 25% in the Siberian zone. There are neither physical nor financial transmission rights in Russia, and thus no hedging of transmission congestion risk.

4.2 DEMAND-SIDE PARTICIPATION

Joskow (2008) suggests that one of the components of competitive markets should be the development of active "demand-side" institutions that allow consumers to react to variations in wholesale market prices, and fully integrate demand-side responses to energy prices and reliability criteria into wholesale and retail markets.

As shown in Table 4.1, the SO forecasts demand for both UC auctions and the capacity market. Large industrial consumers account for more than 50% of total electricity consumption in Russia (see Figure 4.1 in Section 4.4), which can be a valuable source of flexibility in the short- and mid-term. The primary argument in favour of competition is that central planners always get their forecast wrong, overestimating the need for new generation capacity, which leads to unnecessarily high costs for consumers (Kirschen et al. 2004).

The Ministry of Energy approved the "elastic demand curve" in the capacity market in August 2015 for the 2016 and 2017–2019 capacity auctions. The two price points for the linear demand function are regulated by the Ministry of Energy separately for the two price zones, whereas the SO will set respective capacity/load points. The next step should be the introduction of price-responsive demand, similar to what is implemented in the PJM capacity market, where large industrial consumers with necessary infrastructure can offer load reduction in the case of scarcity/emergency.

Table 4.1 Market agents in the Russian electricity and capacity market

Market agents	Day-ahead market	Unit commitment auction	Capacity market
Generators	Offers	Offers on electricity and start costs	Offers on capacity
Regime units	Offers	Priority dispatch	Priority dispatch
Must-run units	Offers	Priority dispatch	
Sales companies	Bids	Estimated by SO	Estimated by SO
Large industrial consumers	Bids	Estimated by SO	Estimated by SO
Guaranteeing suppliers	Bids	Estimated by SO	Estimated by SO
Export/import operator	Bids/offers	Report planned volumes to SO	-
Grid companies	Cover part of transmission losses	-	Cover part of transmission losses

4.3 Flexibility in supply and the role of hydro generation

Hydro resources are regulated by the Ministry of Transport and the Ministry of Natural Resources and Environment. The optimization of hydro generation is constrained by transportation and environmental interests, whereas the remaining flexibility is used by the SO to balance the system in UC auctions, and by the integral constraint for hydro generation over the 24 hours of the trading day by the ATS[16] in the DAM.

[16] The integral constraint applies to generators with limits on daily fuel/water use, for example, gas and hydro generators.

Hydro generators are not allowed to offer prices above zero, but the dual variable on the integral hydro generation constraint represents the water value[17] during the day. This ensures that available hydro reserves are used to maximize social welfare subject to other constraints, and to reduce the effect of the ramp-up/down constraints on generation. Thus, hydro generation is used as a free source of flexibility in the system, whereas non-hydro offers set the price of water during the 24 hours of the trading day.

Time regularities reveal the degree of flexibility of demand and supply in the system, and are exploited primarily for forecasting purposes (Weron 2000; Burger et al. 2004; Weron 2006; Karakatsani and Bunn 2008). Andersson and Lillestøl (2010) and Gjolberg (2010) studied time regularities in the Nordic power market, which has a significant share of hydro generation. The analysis of the Russian power market in Pipkin (2014) reveals that the time-of-day pattern in prices for European price zones exceeds the pattern estimated in Nord Pool by 2–3 times, which reveals poor flexibility in Russia and the different fuel mix in these areas.

The persistence and magnitude of time regularities in the European zone imply that technologies that allow for flexibility on either the supply or demand side can be profitable. The magnitudes of the price differences and time lags between the zones suggest the need to extend the interconnector between the zones.

4.4 THE ROLE OF COAL AND NATURAL GAS

The FST plays an important role in Russia because regulated tariffs exist for water, heat, electricity, natural gas, oil transport, railways, airports, communications, technical control, medical supplies and administrative offences. In addition to tariffs on electricity for the residential sector, tariffs on railway transportation, heat and natural gas have a substantial impact on the electricity sector. Railway tariffs have a direct impact on the cost of transportation of coal, whereas the price of natural gas is directly reflected in the wholesale prices for electricity (see Paper 2 in this dissertation). Heat tariffs have a direct impact on the profitability of the dominant share of thermal generation in Russia, which combines heat and electricity generation.

[17] The water value is a well-established term in the Nord Pool market, which represent the alternative or potential profits of storing the water; see www.sintef.no for more details on the EMPS multi area power-market simulator.

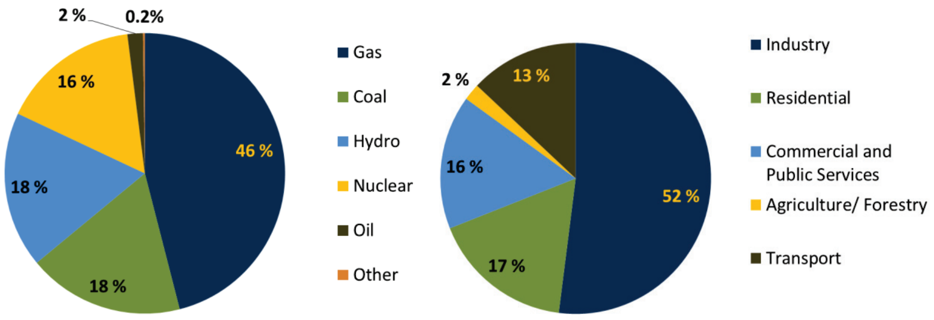

Figure 4.1 Electricity generation by fuel (left) and final electricity consumption by sector (right) (2006, International Energy Agency)

Coal and natural gas account for 18% and 46% of total electricity generation, respectively. While the coal market is liberalized, the Ministry of Energy regulates export volumes. Coal producers can either sell to domestic consumers (based mainly on long-term contracts) or export from the ports in Saint Petersburg or the Black Sea.

The liberalization of the natural gas sector is in a very early stage, as the Saint Petersburg (SPB) Exchange launched month-ahead futures for natural gas in October 2014. Gazprom can sell up to 50% of total volumes constrained to 35 bcm annually, which is approximately 10% of total natural gas consumption in Russia. The volumes traded on the SPB Exchange will have priority access to the gas pipelines, which implies that independent natural gas producers will have access to consumers throughout Russia through the natural gas grid owned by Gazprom[18,19].

4.5 HEAT GENERATION

Heat generation is essential in Russia because of the cold climate, and most of the thermal power plants combine heat and electricity generation. Electricity consumption per capita in Russia is 6500 kWh/year, which is 600 kWh below Germany, 17 500 kWh below Norway and 8000–9000 kWh below Sweden/Finland (World Bank 2011). The tariff for heat does not reflect the actual costs of combined heat and power (CHP) plants, whereas heat generation itself sets constraints on the behaviour of the CHP plants in the wholesale electricity market (Cooke 2005).

[18] Independent producers have previously had very restrictive access to the Gazprom natural gas grid. Russia's FAS said on 9 September 2008 that it was pressing ahead with a fine for "violations" of anti-trust rules in denying pipelines access to a producer in the Tatarstan region (Belton, 2008).
[19] For more information on the Russian gas sector, see "The future of Russian Gas and Gazprom" by Stern (2005).

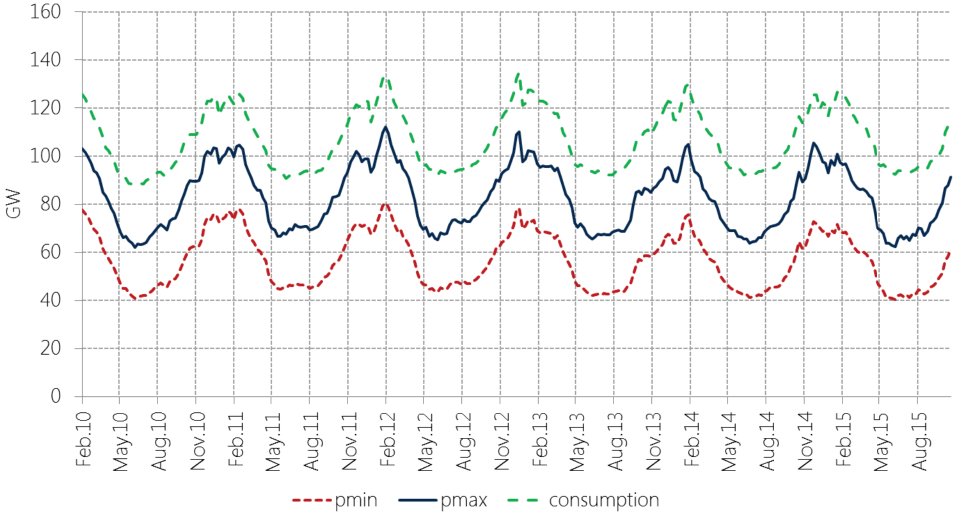

Figure 4.2 Weekly average minimum and maximum constraint on thermal generation[20]

All four papers in this dissertation discuss the crucial role of heat generation in price formation, market power and regulation. Paper 1 illustrates the time-regularities in electricity prices in the European and Siberian zones, which among other factors reflect the minimum generation constraint, primarily on heat generation. The constraint also limits the ability to exert market power because of the formulation of the clearing mechanism as discussed in Paper 3. In Paper 2, we estimate the residual demand for flexible thermal generation corrected for hydro, nuclear and minimum thermal generation (primarily heat) in Northwest Russia. In fact, the residual demand decreases with decreases in temperature, because the increase in heat generation is greater than the increase in demand. Paper 4 discusses regulatory inefficiencies between the heat and electricity markets. Currently, the Ministry of Energy of the Russian Federation is designing a new heat market, but it is not certain when or if such a market will be launched.

4.6 Security constraints

As mentioned previously, both the DAM and UC auctions are cleared based on the SC-OPF, where the latter is also a mixed-integer problem that defines whether power plants should be running or not. The complexity of these non-linear mathematical problems limits the

[20] Calculated as average of the sum of minimum and maximum constraints for all generators during the week.

transparency and the interpretation of the results. Furthermore, the properties of nodal prices lead to some non-obvious effects, where seemingly irrelevant constraints may change the equilibrium solution (Björndal, Gribkovskaia, and Jörnsten 2014).

We have already described how the UC auction sets the premises for the DAM, i.e. the transmission capacity based on the N-1 security constraints, minimum and maximum available generation for running power plants, and to some extent the generation profile for hydro power plants and exports/imports. Paper 4 shows the specific case where the security constraint for the transmission capacity is set in the UC auction, but results in extreme subsidies from consumers in the European zone to consumers in Siberia.

4.7 Discrepancy in time and market rules

The existing literature on the Russian power market, as well as normative and legislative documents, refer to the Russian electricity and capacity markets as one market, while in practice the DAM, UC auctions and capacity market pursue different goals and objectives.

The capacity market comprises power plants that receive capacity payments for their ability to produce. Nevertheless, the solution of the annual zonal capacity market to peak demand and reserves will differ significantly from the hourly SC-OPF problem in the DAM.

While there is no price or direct money transfer between market participants in the UC auction, the dual values on the balancing constraint reveal the locational cost[21] for covering expected consumption, losses and reserve requirements in addition to transmission constraints and start-up costs. Nevertheless, both regime units (security reasons) and must-run units (other reasons, for example, heat generation) avoid competition by having priority in deciding the running status. This is carried out by ignoring the offers of start-up and electricity generation from regime and must-run units.

Paper 4 studies the difference in the maximum accepted offers in the UC auction with and without priority dispatch of must-run and regime units, i.e. it discusses the share of non-competitive offers allowed in the DAM, avoiding competition in the UC auction.

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[21] I refer to the locational cost rather than the locational marginal price (LMP), because UC auctions operate with start-up and generation offers.

4.8 Market power issues

The existing research on the Russian power market focuses primarily on the reform itself (Abdurafikov 2009; Solanko 2011; Palamarchuk et al. 2008) or market power issues limited mainly to the discussion of concentration measures.

Pittman (2007) focuses on the Herfindahl–Hirschman Index (HHI)[22] for different UESs and finds some seasonal variation in the concentration level. The estimated average HHI for the UES values is in the range 1200–1600, but is above 2200 for the Volga region and 2460 for the Northwest region. Cooke (2013) estimates the HHI to be in the range of 1162(1381) to 3305(3771) with (without) trade between the UES. The most concentrated regions for cases with no trade between regions were the South, Northwest and Volga, with the HHI in the range 4000–9000.

Gore et al. (2012) and Chernenko (2015) conclude that transmission constraints lead to the appearance of isolated markets with high generation concentration, whereas strong government involvement in the sector and concentrated ownership/cross-ownership structures do not support competition.

Paper 2 in this dissertation describes the application of the Bresnahan–Lau framework to test for market power issues in Northwest Russia by estimating residual demand and supply curves for thermal generators. The estimated price mark-ups are 7–8% on average for peak hours and 2–3% during night hours.

The overall consensus in the literature is that when transmission constraints are taken into account, the Russian power market is dominated by a few large players with the potential to exhibit market power. However, no previous papers take into account the specific formulation of the clearing algorithm at the power plant level, which has a direct impact on the ability of dominating power producers to execute market power.

[22] The traditional HHI is defined as the sum of squared shares of each power plant in the area. A value of 1800 is typically considered as the threshold for moderate concentration.

In Paper 3, I adjust the traditional HHI and Residual Supply Index (RSI)[23] to fit into the mathematical formulation of the clearing mechanisms for the DAM, UC auction and capacity market. Furthermore, I estimate the transmission-constrained RSI (TCRSI) and test for correlation between the TCRSI and the price/price–cost mark-up (PCMU). There exists positive correlation between the increase in price and increase in the dominant position of a firm such as Gazprom, RosEnergoAtom, Inter RAO, etc.

The implications for market power of the new rules for the capacity market are discussed in the last chapter of Paper 4. The recently proposed elastic demand for capacity limits the degree of competition and invites Gazprom and other large generators to withdraw capacity to increase prices up to the price cap in the European price zone.

5 Summary of the dissertation papers

The four papers that address the research question raised by some of the issues laid out in the previous section, are summarized below.

Paper 1: Time regularities in the Russian power market

More than 65% of the Russian 215 GW generation capacity was commissioned before 1980 and construction of new generation capacity almost stopped at the turn of the century (Khristenko 2006). According to RAO UES (former monopoly on power generation, distribution and transmission), overall investment needed by 2020 was calculated in 2005 to be US$230b for generation and US$160b for transmission and distribution.

Paper 1 focuses on time regularities in Russian power prices and compares these for the Siberian and the European zones for the period 14 September 2007 to 30 June 2014. A set of distinct time regularities is revealed and discussed: "Day-of-the-week pattern", "Weekend pattern" and "Time-of-the-day pattern".

The average difference between the maximum and minimum intra-day prices is about 360 RUB/MWh (40% of the average price level during the day) in zone 1 and only 60 RUB/MWh

[23] RSI refers to the ability of the dominant market participant to set the price or the ability of other market participants to substitute the withdrawn capacity of the dominant firm.

(10%) in zone 2. The average price difference between the zones is about 320 RUB/MWh, but is over 350 RUB/MWh for 15 hours of the day, between 08:00 and 23:00. The weekend effect is more distinctive in zone 1, as prices drop by four percentage points more during the weekend (Friday until Sunday) in zone 1 (9%) than in zone 2 (5%). The price difference between the zones drops by 16%.

The magnitudes of the price differences and time lag between the zones raise the question of extending the interconnectors between the zones. The persistence and magnitude of time regularities in power prices in the European zone imply that technologies that allow for flexibility, either on the supply or demand side, can be profitable.

Investments in new generation infrastructure should take into account the magnitude and persistence of time regularities, because peak/off-peak price differences, for example, can be significant. Similarly, the analysis of investments in transmission should focus on allowing higher exploitation of energy resources in Siberia and increase cross-regional interconnectors to stimulate competition.

Paper 2: Market power issues in Northwest Russia

This article tests for market power in Northwest Russia using the Bresnahan–Lau framework by estimating residual demand and supply curves for thermal producers. Based on the fundamentals of the market, one can identify likely price developments in the future, because the data reveal that the price for electricity in Northwest Russia depends strongly on the price for natural gas.

Demand is divided into three components: exports to the Baltic states and Finland, demand from the central part of Russia and residual domestic demand in the Northwest corrected for nuclear, hydro and minimum thermal generation. The price elasticity of demand is not constant but changes between peak and off-peak hours. The residual demand and supply curves derived using hourly data, are consistent with the market design in the Russian power market.

By using hourly data in the Bresnahan and Lau framework (1982), I find that price mark-ups are close to 7–8% on average for the hours between 10 am and 9 pm and 2–3% for the remaining hours of the day. The residual demand curve elasticity is relatively high during peak hours, which can be explained by the fact that industry accounts for more than 60% of total demand. In addition, demand from Finland/Baltic states and Center FFZ24 have different profiles, such that total demand is most elastic during peak hours and least elastic during the periods of rapid change in consumption.

The increase in natural gas prices was reflected directly in electricity prices in Northwest Russia in the analysed period. The domestic prices for natural gas are expected to increase to the level of European net-back prices, and given that natural gas will still be the main fuel in electricity production, this price increase will also be reflected directly in electricity prices.

Paper 3: Market rules and market power in the Russian electricity and capacity market

The Russian power market is dominated by a few large players with the potential to exercise market power. Meanwhile, none of the papers in the existing literature consider the formulation of the clearing algorithm at power plant level, which has a direct impact on the ability to exercise market power.

The objective of Paper 3 is to take into account the mathematical formulation of the Russian power market in the calculation of concentration measures and investigate the role of transmission constraints using the more detailed framework of the TCRSI.

First, I identify the main differences in market rules between the DAM, UC auction and capacity market. In calculating the HHI and RSI[24], we must keep in mind the special role of hydro generation and the large share of thermal capacity that is constrained by the minimum generation constraint in the DAM. The analysis of the relationship between the TCRSI for a generator and PCMU[25] in the corresponding FFZ is constrained to the 35 largest market participants, including RosEnergoAtom, Gazprom, InterRAO, etc.

The adjusted HHIs and RSIs are substantially lower than the values previously stated in the existing literature for price zones and UESs. Nevertheless, the results show that in some FFZs,

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24 The RSI reflects the ability of the dominant market participant to set the price or the ability of other market participants to substitute the withdrawn capacity of the dominant firm.
25 The PCMU is calculated as (Price – marginal cost)/marginal cost, compared with the Lerner Index defined as (Price – marginal cost)/price.

market concentration measured by the adjusted HHI is above 6000, but also above the traditional HHI, which implies that concentration is even higher when hydro generators and fixed generation are removed from the analysis. The adjusted RSI corrected for transmission capacity illustrates that the result depends strongly on the available transmission capacity.

The TCRSI** (adjusted for hydro and fixed generation) relevant for the DA market reveals that concentration is critical in 10 of 21 FFZs, where 13 of the 35 market participants were pivotal for more than 5% of hours in the analysed period. The situation is even more critical in the UC auctions and capacity market. Dominating generators that are pivotal in the UC auctions can thus set higher offer prices for electricity and avoid the competitive price caps in the DAM. Similarly, these generators will act as pivotal suppliers in the capacity market.

The analysis of the relationship between PCMU and price for FFZ with TCRSI** reveals strong correlation, i.e. the more dominant the position market that participants have, the higher are the prices and PCMU. Correlation does not imply causation and potentially there are other explanations for this effect. The calculation of the TCRSI based on nodal formulation, inclusion of ramp-up/down and integral constraints on fuel/water availability and a focus on generator capacity in estimating marginal cost could obviously reveal more about this relationship.

My analysis supports the previous findings of high market concentration in the Russian power market, but for different reasons. The adjusted HHI is below 1400 on average for all price zones and UESs and the adjusted RSI shows that there exist pivotal generators for more than 5% of hours in the analysed period only in FFZ26 Moscow and FFZ6 Altay. Nevertheless, the TCRSI reveals that market concentration is critical for most FFZs in Russia in the UC auctions, DA and capacity markets. Market concentration decreases the higher is the share of hydro producers and transmission capacity to the neighbouring regions in the Russian power market in general and in addition depends on the share of fixed generation in the DA market.

Paper 4: The regulatory obstacles to competition in the Russian power market

In this article I describe the main challenges and obstacles to competition in the Russian power market, especially regarding the role of the SO. The transmission constraints between the

European and Siberian zones forced by the SO led to enormous subsidization of the Siberian zone by customers in the European zone in the DAM. In addition, must-run generation forced by the system security constraint and demand for heat affects competition in the UC auctions and the capacity market.

The effect of the security constraints on competition in the Russian power market is not discussed in the existing literature, but this effect represents a non-transparent and potentially inefficient regulation for the degree of competition. The SO sets the transmission and generation constraints for the DAM by running UC auctions, but also calculates the transmission capacity and defines regime/must-run generation in the capacity market.

Analysis of the role of the transmission constraints between the Siberian and European zones reveals that consumers/generators in the European/Siberian zones lost up to RUB 6.8m hourly because of the security constraint on transmission capacity between the zones. The simulations confirm that the security constraint on transmission between the zones led to a decoupling of price processes, and only since 15 August 2014 can we refer to the two price zones as one market.

The analysis of supply curves in the UC auctions shows that up to 60% of capacity has priority dispatch (running status at minimum generation), which limits the share of competitive generation capacity in the DA market. The offers from the UC auctions are used as price caps in the DA market, which leads to the situation where must-run units with priority dispatch can potentially offer non-competitive prices first in the UC auctions, thus avoiding competition, and later in the DA market. Further analysis reveals that in some regions there are no alternative suppliers to the must-run generators.

The difference between the system price, ignoring any constraints and the highest accepted offer from must-run generators, is low at the federal district level. This can, to some extent, be explained by transmission constraints. In contrast, when ignoring the effect of transmission constraints at the price zone level, the highest accepted offer from must-run generators is 6–10 times the estimated system price. The priority dispatch of must-run generation leads to stronger competition for other units, which again limits their offers in the DA market.

A similar situation can be observed in the capacity market, where generators can apply and lobby to receive must-run status to avoid competitors receiving tariffs calculated by the FST. Due to the commissioning of new power plants through LTAs in addition to new nuclear/hydro power plants of 7.6 GW and a decrease in the demand for peak capacity of 5.2 GW, the capacity of non-selected units increased from 3.4 GW to 15.3 GW in 2015 according to the SO.

The changes of the capacity market rules in 2016 regarding auctions relate to the must-run generation, excess capacity and linear demand curve. Nevertheless, the slope of the demand curve provides incentives to exert market power for the dominating generators. The price cap constrains the potential profits of generators, whereas the lower bound given by the total installed capacity reduces the incentives for competition.

Since the market coupling of the two price zones in August 2014, the DAM can be characterized as a functioning market, except for the remaining 10% share of the residential demand that receives FST tariffs. There are still issues to resolve in relation to the transparency of the UC auctions that set the constraints for competition in the DAM. The capacity market by no means can be described as liberalized, but rather is a regulated, potentially inefficient and inflexible way to finance new capacity or maintain the existing capacity. Current regulations of must-run capacity constrain further development of the industry and lead to inefficiencies between the heat and electricity/capacity markets, which can be solved only through competitive pricing of heat generation.

6 MAIN CONCLUSIONS

My study examines some of the issues discussed in Section 4. The evidence presented in this dissertation is either absent from the existing literature about the Russian electricity and capacity market or represents a more rigorous evaluation of some important issues.

Paper 1 concludes that investments in new generation should take into account the magnitude and persistence of time regularities. Similarly, the analysis of investments in transmission should focus on allowing greater exploitation of energy resources in Siberia and increase cross-regional interconnectors to stimulate competition. Papers 2 and 3 find market power in the DAM and even greater power in the UC auctions and capacity market. Paper 4 summarizes the main regulatory obstacles for competition because of distortions in the security constraints, subsidies from electricity to heat generation and no incentives for competition in the proposed model for the capacity market. On the basis of these findings, I present the following policy recommendations.

First, increases in consumer response to variations in electricity prices is important because of the low demand elasticity with respect to real-time prices, which is one of the major determinants of the exercise of market power in DA electricity markets. One should also increase consumer participation in the UC auctions and capacity market, where demand is currently forecasted by the SO.

Second, invest in flexibility either on the demand or supply side to deal with the magnitude and persistence of the difference between peak and off-peak prices. Consumers also pay for the capacity used during peak hours, such that the total price difference between peak and off-peak prices for electricity and capacity is extremely large.

Third, substantial welfare gains can be achieved by more competitive pricing of security constraints, thus avoiding distortion of the market. In particular, one should reduce the use of any transmission constraints with maximum and minimum bounds of the same sign, forcing flows in a specific direction independent of market signals in the DAM.

Fourth, upgrading of existing transmission capacity and investment in new capacity is important for the Russian power market. This will not only help relieve the existing transmission bottlenecks and discourage the exercise of market power, but will also address the supply security concerns in the system. Meanwhile, it is important to keep grid tariffs low to increase the importance of market participation for consumers.

Fifth, the electricity market cannot function properly without supporting markets such as the heat and fuel markets. Natural gas will remain the primary fuel for electricity generation in European Russia; however, the deregulation of the Russian natural gas market has been postponed. Similarly, most thermal generators produce heat, which constrains their bidding strategies in the DA market, while heat tariffs are regulated.

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Paper 1

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Time regularities in the Russian power market

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We describe time regularities in the Russian power market and day-of-the-week and intraday price patterns in European and Siberian zones. The magnitudes of the price difference and time lag between the zones suggest extending the interconnector between the zones. The persistence and magnitude of time regularities in the price of power in the European zone imply that technologies that allow for flexibility on either the supply side or the demand side can be profitable.

1 INTRODUCTION

The Russian day-ahead (DA) electricity market was launched in September 2006 after a period of splitting up the domestic monopoly of the Unified Energy System of Russia (RAO UES), separating its services and infrastructures. By liberalizing the power market, the government has been able to gradually increase the domestic price of natural gas[1] toward the same level as European netback prices. Thus, an efficient power market could create a good environment in which to liberalize the domestic market for natural gas, encourage more efficient use of energy and stimulate both infrastructure investments and a more competitive industry in Russia (Ministry of Energy of the Russian Federation 2003). The development of energy markets in Russia will have implications for many European countries, which depend strongly on energy imports from Russia.

More than 65% of Russia's 215 GW generation capacity was commissioned at least a quarter of a century ago, and the construction of new generation capacity almost stopped at the turn of the twenty-first century (Khristenko 2006). Given the expected power infrastructure lifetime, the depreciation of thermal generation had reached 50% and hydroelectric power generation 80% in 2009 (Sidorenko 2010).

[1] Natural gas represents 57% of Russia's total power production in 2009 (International Energy Agency (IEA)).

According to RAO UES (the former monopoly on power generation, distribution and transmission), the overall investment needed by 2020 was calculated in 2005 to be US$230 billion in generation and US$160 billion in transmission and distribution. Investments in new generation should take into account the magnitude and persistence of time regularities, as, for example, peak and off-peak price differences can be significant. Similarly, the analysis of investments in transmission should focus on allowing the higher exploitation of energy resources in Siberia and increasing cross-regional interconnectors to stimulate competition.

The purpose of this paper is to outline time regularities in Russian power prices and compare these within the Siberian and European zones. Based on the ATS[2] hourly price observations for the period September 14, 2007 to June 30, 2014, a set of distinct time regularities is revealed and discussed: the "day-of-the-week" pattern, the "weekend" pattern and the "time-of-day" pattern. Large deviations between peak and off-peak prices induce investment in flexibility on the demand/supply side, whereas large and persistent price differences between the zones should encourage investment in transmission.

2 LITERATURE ON TIME REGULARITIES

Time regularities reveal how technological, economic, structural and physical aspects of the market are reflected in prices. Electricity is a commodity that cannot be stored economically and is thus heavily influenced by economic/business activities and the weather. This seasonality, in turn, manifests itself in the mean-reverting character of spot prices (and loads) at daily, weekly and annual time scales (Weron 2006).

Lucia and Schwartz (2002) propose and estimate one- and two-factor mean-reverting models with deterministic seasonality for the Scandinavian market (Nord Pool) and show that seasonality in spot prices can explain part of the variation in futures prices. Bhanot (2000) analyzes electricity prices, focusing on the mean-reverting and seasonal behavior of the series and the possible regional differences among twelve regional markets in the United States.

Burger *et al* (2004) exploit the fact that seasonal patterns in demand are carried over to the electricity prices via the merit-order curve in order to not only describe price processes on the European Energy Exchange (EEX), but also show how the proposed model can be used for pricing derivatives. Weron (2006) points out the importance of short- and long-term dynamics in modeling loads and prices. Karakatsani and Bunn (2008) study the effects that economic, technical, strategic and risk

[2] Administrator of Trading System of the Wholesale Power Market within the Unified Energy System: see www.atsenergo.ru/ for more details. Daily prices are constructed by taking the mean prices over 24 hours.

factors have on intraday prices and the dynamics of these over time. Koekebakker and Ollmar (2005) present empirical evidence on the Nord Pool forward curve, whereas Koopman *et al* (2005) exploit weekday effects in forecasting the price of power on the EEX, Powernext and the Amsterdam Power Exchange (APX) in the autoregressive fractionally integrated moving average–generalized autoregressive conditional heteroscedasticity (ARFIMA–GARCH) framework. Escribano *et al* (2002) take into account seasonality, mean reversion, stochastic volatility and jumps when modeling the electricity prices of Argentina, Australia, New Zealand, Nord Pool and Spain, showing the importance of jumps with time-dependent intensity.

Andersson and Lillestøl (2010) consider the twenty-four hourly, one-day-ahead electricity prices at Nord Pool as a twenty-four-dimensional vector variable observed on a daily basis through autoregressive integrated moving average (ARIMA) and analysis of variance (ANOVA) models demonstrating typical time regularities as weekday patterns and seasonality. Similarly, Huisman *et al* (2007) focus on the block-structured, cross-sectional correlation patterns between the peak-hour prices and do the same for off-peak prices. Simonsen *et al* (2004) describe daily, weekly and seasonal patterns in Nord Pool prices, linking these effects to the relationship between price and consumption. Gjolberg (2010) raises the question of whether price regularities may offer profitable trading/production planning strategies or profit opportunities from investments in technologies that allow for greater flexibility in energy production and/or consumption.

Russian power sector reform has been well-documented by both Western and Russian researchers.[3] Pittman (2007) and Abolmasov and Kolodin (2002) raise questions about market power despite liberalization, whereas Palamarchuk *et al* (2001) discuss the need for new investments in transmission and generation. The only empirical study on prices by Chuchueva (2010) focuses on DA price forecasts and is only available in Russian. The present paper aims to contribute to the understanding of spot price behavior on the Russian power market and suggest a direction for future investments.

3 MAIN CHARACTERISTICS OF THE RUSSIAN POWER SYSTEM AND MARKET

Russia is the world's fourth-largest generator of electricity (Energy Information Administration (EIA)), behind the United States, China and Japan. The system has a current total electric generation capacity of about 215 GW, and in 2010 Russia generated 1005 TWh of electric power (ATS). The ATS manages the DA market, whereas the system operator (SO) runs a voluntary week-ahead unit commitment

[3] See IEA and VTT for the most complete studies on the recent reform and Kurronen (2006), Cooke (2005) and Sidorenko (2010) for the market in general.

auction for participation in the DA market and the intraday market. Federal Grid Services manages the network and is responsible for the security of the system. Federal Antimonopoly Services seeks to maintain competition.

The Russian power market consists of two price zones: the European (zone 1, Z1) and the Siberian (zone 2, Z2). Nodal pricing was chosen to clear DA auctions, with bids and asks for delivery in 8000 and 3000 nodes in the European and Siberian price zones,[4] respectively. Note that nodal locational marginal prices are presented by Lagrange multipliers on a real power mismatch since the clearing mechanism maximizes social welfare by solving nonlinear optimal power flow problem. Thus, nodal pricing is subject to geographical issues, the size of the market and poor connections between the zones, hubs and nodes. The analyzed zonal price indexes[5] are calculated by the ATS (trading operator) as the volume-weighted average of nodal prices in their respective zones and thus include the impact of network constraints and losses.

Most of the electricity generated in the Siberian zone comes from hydropower, whereas 75% of the electricity generated in the European zone comes from thermal power, mainly natural gas. The government had promised that hydropower plants would be allowed to participate in DA auctions with price bids, but the process has been delayed several times. The domestic prices for coal are not regulated, whereas railway tariffs and maximum-allowed exports are set by the government. Natural gas prices in Russia are expected to increase steadily by 7–15% annually in order to approach the European netback levels, according to the Russian Ministry of Energy (2003).

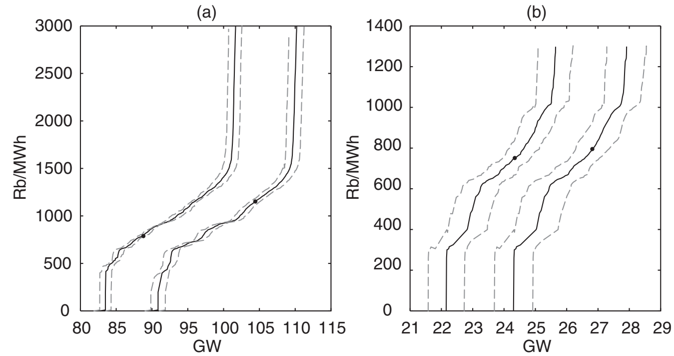
The supply curve[6] in Figure 1 on the facing page shows the fact that there are no price-sensitive bids below an 84 GW load in off-peak hours or below a 92 GW load in peak hours in zone 1. This implies that fixed generation was at around 95% and 87% of consumption in off-peak and peak hours, respectively, in zone 1 during February 2013. In zone 2, the relationship between minimum generation and equilibrium demand was

[4] According to the ATS, the number of congested nodes is close to 2000 and less than 1000 in the Siberian zone. The overall number of nodes in the market is also subject to change due to changes in the topology.

[5] Power producers receive revenues from the capacity market, not only from actual electricity production. The effect of the capacity market on electricity prices is outside the scope of this paper.

[6] ATS started to publish supply and demand bids in 2013 for each zone separately. The demand curve is of little interest as it is an almost vertical line and does not include losses. In addition, the equilibrium depends on network transmission constraints and thus the intersection between demand and supply does not match the equilibrium price. In the text, we refer to the intersection as demand only because increase in demand will be covered by the power plants to the right of the equilibrium price, again due to transmission constraints.

FIGURE 1 Average supply curve for peak and off-peak hours (February 2013).



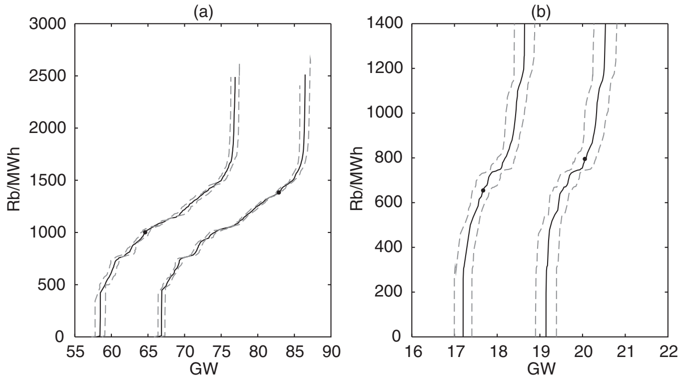
(a) Zone 1. (b) Zone 2. Peak hours: working days, 11:00 to 14:00, Moscow/Siberia time. Off-peak hours: 03:00 to 06:00. We ignore afternoon peak hours. The solid black line shows the average supply curve, and the dashed gray line shows the ±1 standard deviation. The black circle states the average equilibrium zone peak/off-peak price at the corresponding supply curve.

slightly above 90%. The main share of power in Russia comes from combined heat and power plants, hydropower plants regulated by the SO (15% in zone 1, 50% in zone 2) and nuclear power plants (15% in zone 1). Peak demand is close to 94–96% of the available capacity in both zones. The 5% consumption decrease during off-peak hours would easily move the price to zero in zone 1 and reduce it by one-third in zone 2. Similarly, a 5% increase in peak consumption would double the price in zone 1 and meet the maximum available capacity constraint (excluding export/import) in Siberia.

The summer months are typically a maintenance period for large thermal units, and heat production is at a minimum. A 5% decrease in off-peak consumption would not affect prices dramatically, whereas a 5% increase in peak demand would bring the system close to its maximum, where reserve capacity is needed to balance the system.

Figure 1 and Figure 2 on the next page demonstrate the inflexibility in the Russian power system and its dependence on a well-scheduled unit-commitment scheme, maintenance period planning and good demand forecasts. We note little, if any, deviation (vertical shifts in the supply curve) between the average supply curve and the standard deviation of the bids in the respective periods during the day for the months in the examples above (illustrated by the dashed gray lines).

FIGURE 2 Average supply curve on peak and off-peak hours (July 2013).



(a) Zone 1. (b) Zone 2. Peak hours: working days, 11:00 to 14:00, Moscow/Siberia time. Off-peak hours: 03:00 to 06:00. We ignore afternoon peak hours. The solid black line shows the average supply curve, and the dashed gray line shows the ± 1 standard deviation. The black circle states the average equilibrium zone peak/off-peak price at the corresponding supply curve.

4 DESCRIPTIVE ANALYSIS OF PRICES AND PRICE CHANGES, 2007–14

The financial crisis hit Russia by October 2008 and consumption increased by 1.8% rather than the expected 5%. The average load dropped by 5% in both zones in 2009, whereas prices decreased by 6% and 15% year-on-year in zone 1 and zone 2, respectively. By 2011, demand had recovered to 2008 levels in zone 1, though it was still 4% below these levels in zone 2. This was also reflected in the prices, as decoupling is especially clear between 2010 and 2012. Thus, the financial crisis gave the Russian government additional time to create a good environment and incentives to invest in new capacity and technology. Since 2004, little extra capacity was introduced, investments are still low and old generation units cannot provide competitive prices, ie, prices will go up in the long run, taking into account the policy of the Federal Tariff Services (FTS).

As for other power markets, Russian power prices are extremely volatile. Figure 3 on the facing page describes the weekly (mean) price from September 14, 2007 to June 30, 2014 and, as can be seen, minimum and maximum prices (black area for Z1, gray for Z2) during the week deviate substantially from the mean. Table 1 on the facing page summarizes the main descriptive statistics on prices for the two zones.

FIGURE 3 Weekly power prices (and minimum/maximum level), September 2007–June 2014, Europe (Z1) and Siberia (Z2).

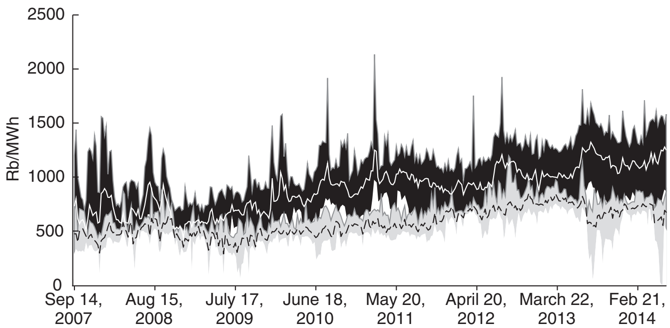


Figure shows minimum/maximum price zone 1 (black area), minimum/maximum price zone 2 (gray solid line), price zone 1 (white solid line) and price zone 2 (black dashed line).

TABLE 1 Price changes, September 2007–June 2014.

	Price (Rb/MWh)		Hourly dlog price changes (%)		Daily dlog price changes (%)		Weekly dlog price changes (%)	
	Mean	**SD**	**Mean**	**SD**	**Mean**	**SD**	**Mean**	**SD**
Z1	892	252	0.0011	12.3	0.0260	8.0	0.1517	6.9
Z2	573	136	0.0008	28.0	0.0194	18.8	0.0996	9.8
Z1–Z2	324	198	0.0015	673.5	0.0340	397.8	0.2283	291.9

SD denotes standard deviation.

The European zone price was 892 Rb/MWh on average for the period analyzed, with a standard deviation of 28% of the mean. The volatility in Siberia was 24% of the average price level at 573 Rb/MWh. The lower price level and volatility in Siberia can be explained by the fact that 50% of its power comes from hydro producers who are not allowed to bid on the market. Thus, the value of flexibility that hydro producers represent is not priced in the market.

Disregarding the spikes (normally the result of extreme weather conditions/outages), more than 14% and 22% of the 2482 days had a price change of $\pm 10\%$ or more in zones 1 and 2, respectively. In all, there were 4 and 14 spikes with a daily price change above 50%, and jumps in daily price change above 30% occurred 19

TABLE 2 Percentage of observations of price changes in interval range.

(a) Daily

	Interval range							
	0–5%	**5–10%**	**10–15%**	**15–20%**	**20–30%**	**30–40%**	**40–50%**	**>50%**
Z1	60	26	9	2.74	1.85	0.40	0.20	0.16
Z2	56	22	11	4.83	4.51	1.17	0.32	0.56

(b) Hourly

	Interval range							
	0–5%	**5–10%**	**10–15%**	**15–20%**	**20–30%**	**30–40%**	**40–50%**	**>50%**
Z1	68	19	8	3.03	1.84	0.56	0.20	0.63
Z2	86	8	3	1.25	0.90	0.33	0.10	0.17

and 51 times in zones 1 and 2, respectively. Overall, the daily price changes stay below 20% in absolute terms, except for 2.6% and 6.6% (or 65 and 163 days) of 2482 observations for the two zones, respectively. See Table 2 for more details.

Zone 2 exhibits higher volatility in daily price changes than zone 1, whereas the situation is reversed when it comes to hourly prices. For the period from September 14, 2007 to June 30, 2014, we can observe 827 hourly price changes above 30% in zone 1 compared with just 359 in zone 2, and similarly 373 and 100 price changes above 50% for the two zones, respectively.

Normal probability plots for hourly and daily prices show that the prices exhibit a bimodal distribution. Hourly prices have a positive skew of 0.05 for zone 1 and 0.036 for zone 2; daily data skews are -0.10 and 0.04, respectively. Both hourly and daily data show excess kurtosis from -0.77 to -0.24, whereas dlog price changes have an extreme kurtosis of 459 and 1455 for hourly price changes and 8 and 174 for daily price changes for zones 1 and 2, respectively.

By applying the approach of Lucia and Schwartz (2002) and Huisman and Mahieu (2003), the DA price can be represented as the sum of two independent components: a deterministic component and a stochastic component. The deterministic component accounts for predictable regularities in the price process. By employing an ordinary least square (OLS) regression with dummy variables representing time regularities, we can model the deterministic component in price/price changes, allowing for differences in mean price levels over, for example, hours, days or other time cycles.

5 AROUND-THE-CLOCK PATTERN

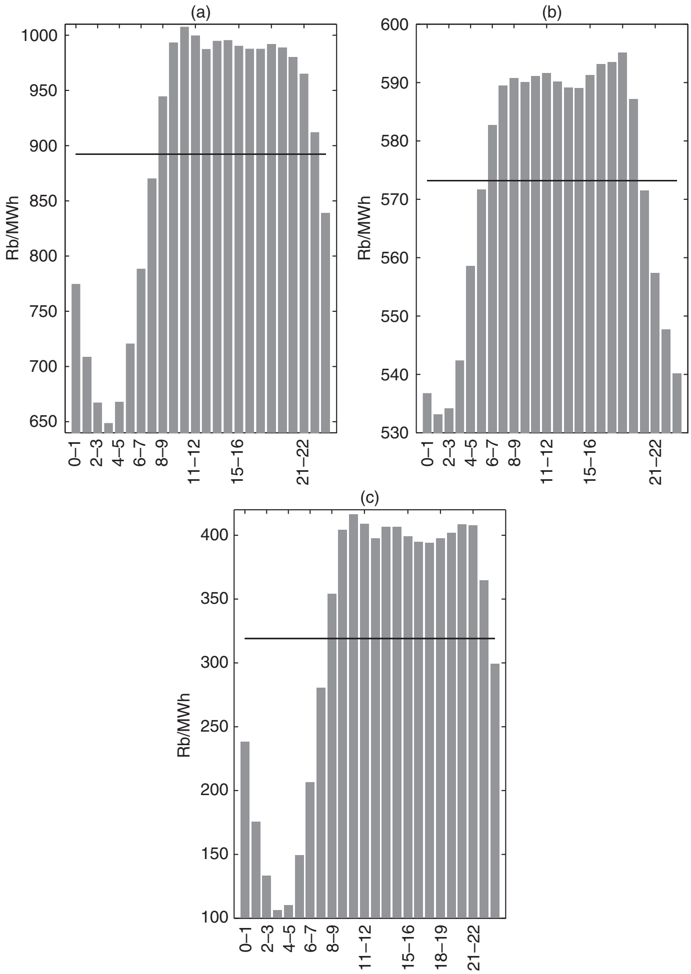
The OLS regression with dummy variables for each hour during the day (one as constant/reference) reflects mean price levels per hour, as illustrated in Figure 4 on the next page. The lowest price for power in zone 1 occurs between 03:00 and 04:00. Then the price increases until 10:00, is relatively stable during the day and starts to decrease around 19:00–20:00. The ATS DA power market operates in Moscow time, whereas in our case there is a three-hour time difference between the zones. Thus, we can observe the morning peak is slightly prolonged and moved to 08:00–09:00 Moscow time (11:00–12:00 Siberian time). Nevertheless, the daily price peaks at 18:00, but the variations are very small. The average difference between maximum and minimum intraday prices is about 360 Rb/MWh (40% of the average price level during the day) in zone 1 and only 60 Rb/MWh (10%) in zone 2, which confirms the previous findings of higher intraday volatility in hourly prices for zone 1. The average difference in hourly prices between the zones is about 320 Rb/MWh, whereas the minimum/maximum price differences of 106 Rb/MWh and 420 Rb/MWh, respectively, occur at 04:00 and 11:00 Moscow time. Meanwhile, the price difference between the zones is above 350 Rb/MWh for fifteen hours, between 08:00 and 23:00.

The explanatory power for the model on price levels is 25% for zone 1 and 3% for zone 2, whereas by including trend the explanatory power increases to 70% and 52% respectively for the zones. Similarly, the model explains 40% of the variation in price difference between the zones and 28% without trend. Obviously, electricity price development in Russia is driven by not only the tariffs set by the FTS on natural gas, railway transportation and transmission, but also differences in economic development between the two zones, which might explain the 0.42% difference in trend coefficient (0.97% in zone 1 and 0.55% in zone 2).

The coefficients for hourly dummies for the price changes also show that the pattern in Figure 4 on the next page is stable (standard deviations of the estimated coefficients are relatively low). The model shows that the maximum average hourly price change is 10% and 4% at 07:00 and 05:00 in zones 1 and 2, respectively, whereas the minimum of -10% for zone 1 is at 02:00 and the minimum for zone 2 is -3% at 22:00.

We can also state that the price difference between the zones exhibits a strong intraday pattern varying between 100 and 420 Rb/MWh on average. The price difference starts to decline at 22:00, with the strongest drop of 10% at 02:00. It increases from 05:00 until 11:00, when it plateaus at around 400 Rb/MWh. The price difference is relatively stable between 10:00 and 22:00, varying by some 10–20 Rb/MWh. These are small but significant price changes. The 0.43 Rb/MWh per hour trend coefficient implies that by July 2014, or 59 568 observations, the trend stands for some 300 Rb/MWh to the average price difference between the zones, which gives us an average price difference of 520–570 Rb/MWh between 10:00 and 22:00 by summer

FIGURE 4 Hourly mean price (Rb/MWh) in Z1 and Z2 Moscow time.



Estimation results are available from the author upon request. (a) European zone. (b) Siberian zone. (c) Z1 − Z2.

2014. In other words, the trend adds up to around a 43 Rb/MWh price difference between the zones annually during the analyzed period.

6 DAY-OF-THE-WEEK PATTERN

Figure 5 on the next page illustrates the daily average price through the week during the analyzed period. Mondays represent the highest average price for the analyzed period: 917 and 580 Rb/MWh in zones 1 and 2, respectively, and 335 Rb/MWh for the price difference between the zones. The drop in price from Wednesday to Thursday in zone 1 and from Thursday to Friday in zone 2 continues until Monday, when the price jumps by 11% and 6% on average in zones 1 and 2 respectively. The price difference between the zones increases by 18% from Sunday to Monday, but it drops by 7% and 10% on Saturday and Sunday.

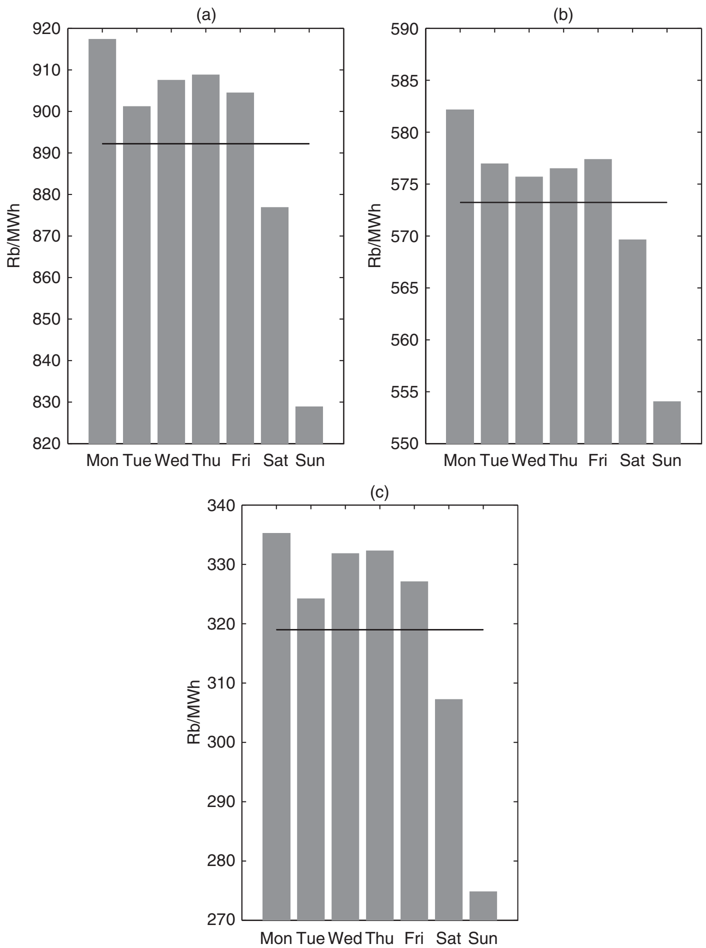
Dummy variables for price levels on Monday through Saturday are significantly different from the constant (Sunday). The weekend effect is more distinctive in zone 1, as prices drop by 4 percentage points more during the weekend (Friday until Sunday) in zone 1 (9%) than in zone 2 (5%). The price difference between the zones drops by 16%. All dummies for price levels are significant for both zones and the price difference between the zones, whereas t-values are relatively close to the 5% threshold in zone 2. Price changes on Sunday are significantly different from zero, and all other dummies are different from the reference. The price changes on Tuesday and Saturday are not significantly different from the price changes on Sunday in zone 2.

For the price difference between the zones, we can observe a strong Monday effect (with a significant 18% jump) and a weekend effect. Overall, dummies explain 37%, 3% and 2% of the variation in price changes in zone 1, zone 2 and the price difference between the zones, respectively. By applying a model with trend on daily price levels, the explanatory power increases to 70% for zone 1, 54% for zone 2 and 23% for the price difference between the zones. The trend coefficient is 0.24 Rb/MWh per day in zone 1 and 0.13 Rb/MWh per day in zone 2. As shown in Figure 6 on page 84, the average price difference between the zones is close to 320 Rb/MWh. When correcting for the different linear trend coefficients, the difference is closer to 200 Rb/MWh.

7 THE PERSISTENCE OF THE INTRADAY PATTERN

The above sections show that there are deterministic patterns during the day and week. This is consistent with the previous research on power markets and a sign of a healthy power market, which reflects changes in supply and demand through the day and week. The deterministic dynamics can be explained by the fundamental and technological factors of power markets and production. An increase in demand leads to a situation in which production from less efficient, and thus more costly,

FIGURE 5 Mean daily price (Rb/MWh) over the week.



Estimation results are available from the author upon request. (a) European zone. (b) Siberian zone. (c) Z1 − Z2.

power plants is needed to balance the market. Transmission congestion also plays a significant role in strengthening the above patterns.

By using a linear regression model with 168 dummies, for each hour of the week, for example, MON1, MON2, …, SUN24, to explain price/price changes, we can confirm that a 168-hour pattern exists, implying that intraday regularities differ either in shape or in level depending on the weekday.

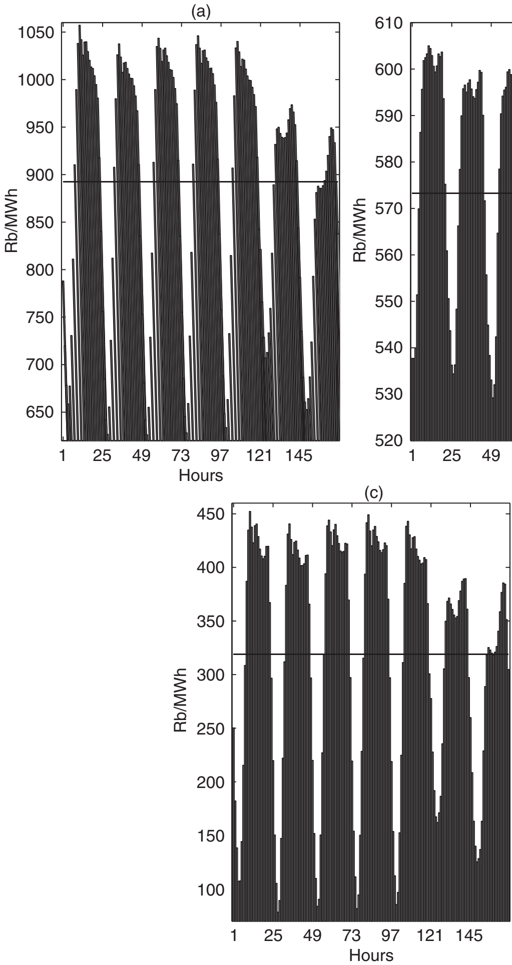
As can be seen in Figure 6 on the next page, the shape of the intraday pattern is quite similar on working days. For weekends, prices are lower, but the shape of the price patterns is also different. The overall 168-hour pattern explains 28% of the variation in prices in zone 1, 3% in zone 2 and 30% of the variation in price difference between the zones. Adding trend increases the explanatory power of the OLS model with 168 dummies to 72%, 52% and 43% for zone 1, zone 2 and the price difference between the zones, respectively. Without trend, there are 153 dummies that are significantly different from the reference hour (Monday, 07:00) in zone 1, 77 in zone 2 and 155 for the price difference between the zones. Similarly, for the model on price changes the explanatory power is strongest for zone 1 with 22%, 1% for zone 2 and 10% for price difference between the zones.

8 POTENTIAL FOR WELFARE GAINS

By analyzing time regularities in both zones, we can clearly observe that price levels for the different time regularities are significantly different from the reference period. On average, the price difference between the zones was close to 320 Rb/MWh (55% of the average price in Siberia) in the analyzed period. Time regularities are strong and persistent in zone 1, as well as in the price difference between the zones, whereas intraday and day-of-the-week patterns are rather flat in zone 2. In addition, the three-hour difference between the Moscow and Siberian time zones leads to a lag in the consumption pattern and thus different dynamics in price difference between the zones. The highly significant weekday and hourly profiles in zone 1 are a reflection of the unit commitment scheme, which constrains the minimum and maximum power generation available, as illustrated in Figure 1 on page 75 and Figure 2 on page 76. Additional, flexible generation, which could extend the range between the minimum and maximum available price-sensitive supply, would be profitable for investors and also increase social welfare by flattening the price profile during the day and week.

Nevertheless, the most obvious issue seems to be the level of price difference between the zones. While central and southern hubs in the European zone have poor balance, the production in both the Urals/Volga region and Siberia is constrained due to poor east–west interconnectors. As mentioned earlier, a large number of power plants need extensive maintenance periods, which obviously constrains their overall availability and reduces their utilization rates. In addition, transportation costs of

FIGURE 6 Intraday price pattern through the week (Rb/MWh).



Estimation results are available from the author upon request. (a) European zone. (b) Siberian zone. (c) Z1 − Z2.

approximately 300–500 Rb/MWh[7] explain the large price difference between the zones.

The transmission capacity between the European and Siberian zones (via the Volga hub) is limited to 2 GW (Siberia–Urals) and 3 GW (Urals–Volga). The enormous hydro-capacity potential in Siberia of 850 TWh annually cannot be exploited for now (Saveliev and Chudinova 2009), whereas strong time regularities in zone 1 could be easily reduced by flexible hydro. Hydropower plants can reduce the risk of both zero and extreme prices. This can also be profitable for thermal generators, as the number of zero-price hours decreases and thermal units depend on a stable price profile to optimize bidding in unit commitment.

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[7] 18–30 US$/tonne for coal in railway transportation implies 200–355 Rb/MWh in additional costs for a coal power plant with 30% efficiency. 800–1200 RUB/mcm in transportation costs for natural gas leads to 450–700 Rb/MWh in transportation costs for the power plant with 30% efficiency.

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Paper 2

MARKET POWER ISSUES IN NORTHWEST RUSSIA

Abstract

The purpose of this article is to examine market power in the energy sector in Northwest Russia using the Bresnahan–Lau framework by estimating demand and supply curves. Based on market fundamentals, one can also identify likely future price developments because the data reveal that the price of electricity in Northwest Russia depends strongly on the price of natural gas, which is regulated and expected to increase. The results show that the price elasticity of residual demand varies throughout the day. Consequently, the potential to exert market power may also vary over time. The estimated price mark-ups are in the range of 1–8%, and are at the lower end of this range during night hours.

Key words: Russian power market, market power, Bresnahan–Lau

Acknowledgements: Special thanks go to Ole Gjølberg, Olvar Bergland and Mette Bjørndal for valuable discussions.

1 Introduction

The current Russian power market emerged as a result of significant deregulation of the system starting at the beginning of the century and was transformed into the Administrator of the Trading System (ATS) Day-ahead market (DAM) in 2006. The monopoly position of RAO OES was dissolved by splitting the company into 26 wholesale and territorial generation companies. Cooke (2005) and Pittman (2007) still characterize the market as moderately to highly concentrated depending on the season and the geographical scale. For Northwest Russia, Cooke (2013) calculates that the three largest producers account for 74% of capacity and the

Herfindahl–Hirschman Index (HHI[1]) is 3771, but is 5108 when summer price takers are excluded and 5723 when winter price takers are excluded[2].

Despite dramatic changes in the electricity sector, prices for natural gas are still regulated by the Federal Tariff Services (FST), but are expected to converge gradually to the European net-back prices according to the Ministry of Energy of the Russian Federation. This implies that the 45% of power generation in Russia that is fuelled by natural gas will face increasing fuel prices and this will be reflected in higher electricity prices, as gas-generated power clears the market.

There are no econometric studies on the properties of supply or demand in the Russian power market. The primary measures of market power in the existing literature on the Russian power market are concentration measures.

This article aims to estimate price mark-ups based on the Bresnahan–Lau (BL) framework by estimating residual demand and supply curves for thermal generation in Northwest Russia. The secondary goal of this article is to contribute to the understanding of the role of thermal power generation in Northwest Russia.

The paper is organized as follows. A literature review is presented in Section 2. Section 3 describes the main characteristics of the Russian power market. Section 4 presents the BL framework used to model the power market in Northwest Russia. Sections 5 and 6 discuss the demand and supply estimation, while Section 7 concludes.

2 Literature on Market Power in Power Markets

Market power issues in the Russian electricity market have been discussed by Cooke (2005), Pittman (2007), Gore et al. (2012), Cooke (2013) and Chernenko (2015). These papers present

[1] The traditional HHI is formulated as the sum of squared shares of each power plant in the area. A value of 1800 is typically considered as the threshold for moderate concentration.
[2] Under the market rules, nuclear and hydro generators are subject to priority dispatch, with combined heat and power generators added to priority dispatch during the heating season (Cooke, 2013).

high values for the HHI and point out that the transmission grid in Russia cannot accommodate a free market, as grid constraints mean the number of participants is limited[3].

An analysis of locational marginal prices (LMPs) should be done by including detailed information about installed generation capacity and topology of the transmission grid[4] (Hogan 1997). Soofiabadi (2014) proposes a distinct metrics for detection of market power in nodal markets. Harvey and Hogan (2000) state that nodal pricing is less favourable for a monopolist compared with zonal pricing. Holmberg and Lazarczyk (2012) and Björndal et al. (2014) continue theoretical discussions about nodal and zonal pricing, congestion management and market power.

Hjalmarsson (2000) and Mirza and Bergland (2012) focus on whether bottlenecks generate market power in the Nord Pool area in the BL framework. Both articles show that the Nord Pool market is competitive and that short-run mark-ups are low on average, but significantly greater when the grid capacity is reduced. Joskow and Tirole (2000) show that both financial and physical transmission rights can promote market power in the networks with or without loop flows.

Borenstein, Bushnell and Stoft (2000) discuss the weaknesses of concentration measures and propose an alternative method to estimate market power based on simulations and the use of plant-level data. Green and Newbery (1992) simulate supply function equilibria for the UK market and find that prices can substantially exceed marginal costs. The results from Borenstein, Bushnell and Knittel (1999) suggest that market power in California is much more prevalent when demand is modelled as less responsive to price changes. Green and Newbery (1997) examine the British market and find that early in the deregulation process, the two dominant generators possessed “very considerable” market power. Holmberg and Newbery (2010) discuss welfare losses and policy implications in a supply function equilibrium framework that provides a game–theoretic model of strategic bidding in oligopolistic wholesale electricity auctions.

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[3] The studies refer mainly to the DAM, but annual capacity auctions were regulated by the Federal Antimonopoly Services by setting a price cap in most of the FFZ because of the limited number of generators.

[4] Nodal prices are the result of the solution to the optimal power flow problem including constraints on the active and reactive power.

The data available on Northwest Russia are aggregated by fuel type or free-flow zones (FFZs). Thus, the analysis in this paper is limited to the discussion of the effect of flexible thermal generation on market power in Northwest Russia using the BL framework.

3 Description of Russian Power Market

The DAM is a mandatory market in which hourly LMPs are calculated for the next operating day based on generation offers, demand bids and grid constraints. As for the other power markets, Russian market participants that are qualified and registered at the ATS deliver their bids and offers for clearing in the DAM. Each generator can submit a maximum of three offers above zero[5] for every trading hour for their available capacity between the minimum and maximum capacity confirmed/defined by the system operator (SO) through the voluntary unit commitment (UC) auctions for three days-ahead. The units that were not allocated in the UC auctions and hydro power producers are not allowed to ask a price above zero in the DAM.

The SO also runs the annual capacity auctions, which were designed to stimulate investment in new capacity and support maintenance of the existing power plants. The peak demand is calculated by the SO, whereas the antimonopoly services have put price caps at the major part of the FFZs. FFZs are defined as areas without congestion (inside the zone) and calculated by the SO based on the estimate of peak load and available generation and transmission capacity.

The ATS solves the security-constrained optimal power flow (SC-OPF) problem for approximately 8000 nodes[6] and 12 000 power lines and for all 24 hours of the day, subject to the balancing constraint, maximum/minimum constraints on generation and flows, the integral constraint and ramp-up/down constraints on generation. Nodal prices are dual values on the balancing constraint, including shadow prices on transmission and prices of losses. Thus, price differences between nodes reflect transmission constraints and losses. ATS publishes an FFZ price index which is a volume-weighted average of nodal prices in the FFZs.

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[5] The three bids for generation are above pmin, and the three between zero and pmin are all dependent on technology.

[6] The actual number of nodes changes because of maintenance of the grid, availability of power plants, etc. ATS publishes monthly reports with updates of the list of nodes in the topology.

The Russian power market consists of 15 FFZs in the European price zone (Z1) and six FFZs in the Siberian price zone (Z2). The analysis in this article is constrained to modelling supply and demand in Northwest Russia. The latter is defined as FFZ27 West and FFZ28 Kolskaya. I omit FFZ28 Kolskaya because flows between the zones are constrained and dependent solely on the long-term schedule of the Kolskaya nuclear power plant, which accounts for 45–50% of generation in FFZ28 Kolskaya. FFZ24 Center, Republic of Belarus, Estonia, Latvia and Finland represent the main import and export regions (see Figure 4.2).

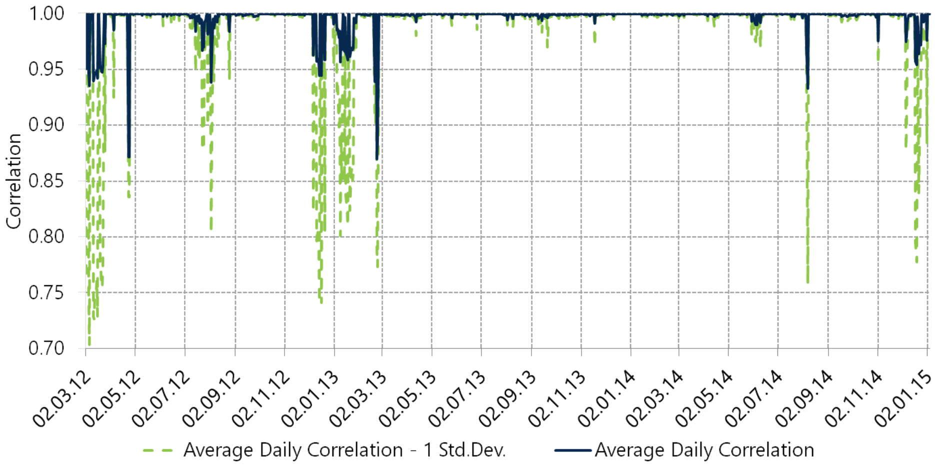

Figure 3.1 Correlation between the 200 largest nodes in FFZ27 West

As mentioned previously, the definition of FFZ in capacity market implies no congestion inside the zone. Figure 3.1 shows the daily correlation for 24 hours between the 750 kV node in Leningradskaya oblast and the other 199 nodes in FFZ27 West divided equally by 50 nodes per federal subject (oblast) in the region for the period from March 2012 to January 2015. Nodal price includes the cost of producing energy and delivery: losses and/or transmission congestion lead to “out of merit” dispatch to satisfy system constraints (Litvinov et al. 2004). Transmission congestion is the main reason for occasional changes in the price correlation between the nodes. The average correlations between nodal prices is close to 1, which implies no major congestion inside FFZ27 West during the analysed period and consequently can treat FFZ27 as one zone, where nodal prices differ only because of losses. Obviously, this ignores the Kirchoff’s circuit laws for the flows inside the zone, while transmission to other regions is primarily throughout direct links (400 kV to Finland, 330 kV to Latvia, Estonia and Belorussia and FFZ28 Kolskaya, and 750 kV to FFZ24 Center).

The complexity of SC-OPF market clearing algorithm in DAM constraints the analysis of the Russian power market by other approaches. One of these is to estimate mark-ups on the basis of actual bid curves published by the ATS for each price zone instead of estimations of those. Obviously, these can include potential bias, when it comes to market power as these bids can be above or below actual marginal costs. Another possibility is to estimate marginal cost curves on the basis of engineering data on heat-rates and fuel prices and compare with actual prices illustrated in Figure 2 in Appendix 1. Natural gas is a primary source for flexible power generation in FFZ27 West in addition to nuclear (36%) and hydro (9.5%) generation. Nuclear generation is not flexible to set prices on average. Hydro generators are not allowed to offer prices above zero in DAM, but the dual variable on the integral hydro generation constraint represents the water value[7] during the day.

Nevertheless, the relationship between the marginal costs of generation is not straight forward in the nodal market even without market power. In a case without congestion only marginal unit will set the nodal price at its location. The remaining fully dispatched generators will receive the price above their offers corrected for losses. Loss component is calculated based on the actual topology and the flows since flows and consequently losses are part of the solution of the SC-OPF problem. The mathematical problem consists of voltage and phase angle in 8000 nodes, resulting in active power flows through 12 000 power lines constrained by 600-800 sections and offers from 800 regime-generation units (RGE) defined by the ATS based on 3 500 generators. With variation in demand and transmission capacity constraints, the estimation of marginal cost for the marginal unit becomes virtually impossible.

[7] The water value is a well-established term in the Nord Pool market, which represent the alternative or potential profits of storing the water; see www.sintef.no for more details on the EMPS multi area power-market simulator.

4 Bresnahan–Lau Framework Modelling of the Power Market in Northwest Russia

The BL model is based on the assumption that a profit-maximizing firm will produce where marginal cost equals perceived marginal revenue, $P = MC = MR$ in a perfectly competitive market, but $MR<P$ when market power exists (Hjalmarsson 2000). The model assumes price-taking buyers, which is relevant for the Russian power market. The BL framework allows us to test for market power without knowing the cost function or demand function *a priori*. By introducing a rotation variable one can identify the demand and supply functions, but most importantly we can find whether the solution corresponds to a perfect market or monopoly.

Let the market demand curve be:

$$Q = D(P, X; \beta) + \varepsilon \ , \qquad (1)$$

where $D(.)$ is the inverse demand function, X is a vector of factors shifting demand, β is a vector of parameters and ε is an error term.

Following the standard approach of Bresnahan (1982) and Lau (1982), if the firms are not price takers, the industry supply relationship is given by:

$$P = C(q, W; \delta) - \lambda h(P, X; \beta) + \eta \ , \qquad (2)$$

where P is the market price, q is the total production, W is a vector of factors shifting the marginal cost curve, α is a vector of parameters and η is an error term, such that we have:

$$h(P, X; \beta) = \frac{Q}{\partial Q(.) / \partial P} \ . \qquad (3)$$

Thus, $P + h(P, X; \beta)$ is the marginal revenue. The parameter λ is the mark-up parameter measuring the degree of market power, where $\lambda = 1$ implies monopoly and $\lambda = 0$ implies perfect competition.

Bresnahan (1982) shows that identification in estimating a linear demand function is guaranteed if one introduces a rotation variable that shifts the slope of the demand function, whereas Lau (1982) extends this result without assuming a particular functional structure for the reduced form price and quantity function. By introducing a rotation variable in the demand/supply estimation, one can distinguish between an equilibrium where a cheap producer exerts monopoly power and an equilibrium with costly supply in a perfect market as illustrated in Figure 4.1.

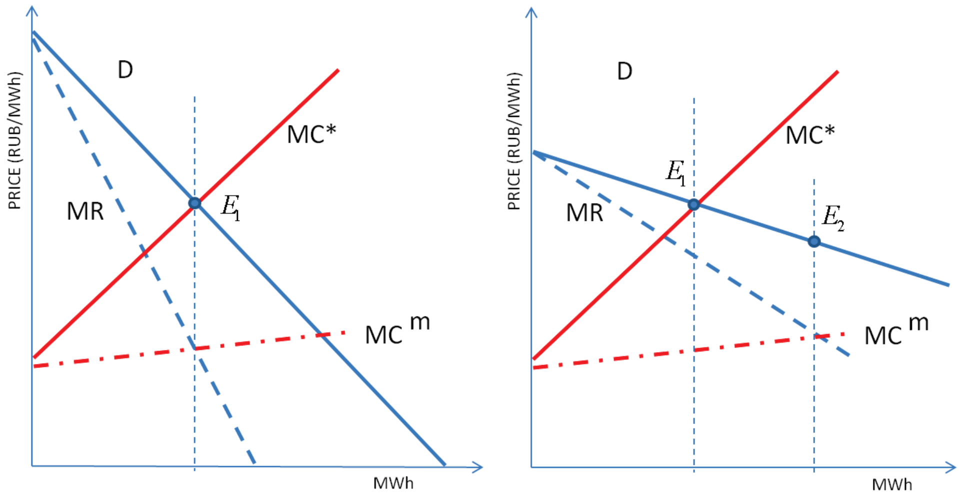

Figure 4.1 Supply and demand identification in the BL framework

Market power is defined as the ability to profitably alter prices away from competitive levels (Stoft, 2002). The traditional approach to analysing whether prices exceed marginal costs has been the calculation of the Lerner Index, which can be expressed as (Price – MC)/Price, where MC equals the average marginal cost of the dominating generators. Perloff et al. (2007) show that the mark-up can be calculated using the Lerner Index as $(P - MC)/P = -\lambda / \varepsilon_p$, where ε_p is the demand price elasticity and λ is the coefficient of market power in supply equation 2.

Financial and fixed costs (long-run marginal costs) for capacity and start-up costs are recovered in the capacity market and UC auctions, respectively. Thus, one can apply the Lerner Index directly. Meanwhile, Newbery (2008) points out that the combination of low demand elasticities with a small number of competing firms would suggest a very high Lerner Index and an improbably high ratio of profits to revenue. In the BL framework, this implies that the size of the price mark-up depends directly on the absolute value of the estimated demand elasticity.

Bresnahan (1982 and 1989), Lau (1982) and Reiss and Wolak (2007) show that identification of market power depends on the assumptions on the functional form for demand and costs of generation. Kim and Knittel (2006) compare direct measures of mark-ups and marginal costs to estimates based on the static conjectural variations first-order conditions of an industry. The results show that linear model produces the most accurate estimate of the direct market power level compared to log-log and linear-log models, but all three models overestimate market power level. In addition, linear demand model yields the lowest elasticity estimates. I assume linear demand function for domestic demand in FFZ27 West and for demand from other regions as illustrated in Figure 4.4.

Borenstein et al. (2000) point out that methods of estimating market power at the market level capture all inefficiencies in the market, not just the exercise of market power. Cho and Kim (2007) decompose the difference between market price and the marginal production costs of the marginal generator into the market power and the inefficiency arising from the network constraint[8]. As mentioned previously, nodal prices include both loss and transmission congestion components, which implies that the results must be interpreted with some caution.

The main export region for power from FFZ27 West is FFZ24 Center, which represents the main consumption driver in Russia[9]. Total capacity of the transmission line is 2600 MW, which is approximately one-third of peak consumption in FFZ27 West. Transmission between FFZ27 and FFZ24 is constrained through min/max constraints on sections, i.e. the sum of flows through several power lines. Sections and the transmission capacity of sections are defined by the SO.

Kolskaya nuclear power plant accounts for 80% of installed capacity in Kolskaya FFZ28. The transmission capacity between FFZ27 West and FFZ28 Kolskaya is limited to 600 MW and depends mainly on the maintenance periods at the Kola nuclear power plant. In addition, the two 330 kV power lines from FFZ28 to FFZ27 are directly linked to the Kolskaya nuclear power

[8] Cho and Kim (2007) demonstrate that the welfare loss due to the finite transmission capacity accounts for 29-30% of the total annual welfare loss, while remaining portion can be explained by the market power exercised by the generators in California electricity market between 1998 and 2000

[9] Moscow oblast is a separate area, where FFZ26 is inside FFZ24.

plant and cannot supply north of FFZ28. Thus, flows from Kolskaya FFZ28 to FFZ27 West can be explained by the exogenous nuclear production, i.e. long-term planning.

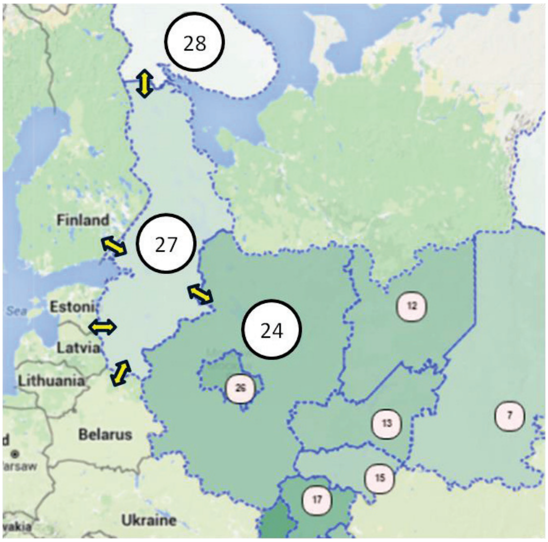

Figure 4.2 Geographical illustration of transmission between the regions in the analysis

I assume also that flows from Russia to the Republic of Belarus, Baltic states and Finland (FBRELL) have different price elasticities compared with demand from FFZ24 Center. Finland and the Baltic states are bidding areas in the Nordic market, but based on the data from ATS it is not straight forward to distinguish between flows to Nord Pool area and Republic of Belarus. Thus, I assume that the Republic of Belarus, Baltic states and Finland (FBRELL) represent one export area[10]. In practice, I estimate the price elasticity of export agent's[11] bids in the DAM based on the data from ATS, i.e. the solution of the SC-OPF model (not the physical flows).

Brennan (2002) argues that the primary context in which market power might be exercised is when the industry is facing capacity constraints. Nevertheless, the strict definition of congestion on the set of power lines between FFZ24 Center and FFZ27 West applies only to 0.45% of hours in the analysed period (205 out of 45 744 hours). The section data for FBRELL are incomplete

[10] The Republic of Belarus exports to Lithuania, whereas the 330 kV link from Novosokolniky (FFZ27 West) and Lithuania is through Novopolock (Belarus). Estlink is a set of HVDC submarine power cables between Estonia and Finland.
[11] InterRAO holds a monopoly on the export and import of electricity in Russia.

and do not necessarily represent the true degree of congestion between the FBRELL and Northwest Russia. Further investigation of actual flows and network congestion is beyond the scope of this article and I assume that the capacity between FFZ27 and FFZ24 Center or FBRELL is not congested.

Notice also that about 45% of electricity in FFZ27 is consumed by energy-intensive industry and an additional 15% by other industrial consumers. However, demand curve for European price zone published by the ATS shows only minor price elasticity (99,875% of demand is price-inelastic).

The aggregated demand can be represented by "domestic" residual demand, flows to FFZ24 Center and net exports to the FBRELL as follows:

$$Q = Q_d + Q_c + Q_f = D_d(P, X; \alpha) + D_c(P, Y; \beta) + D_f(P, Z, \gamma) + \varepsilon \,, \qquad (4)$$

where subscript *d* refers to domestic demand, *c* refers to demand from FFZ24 Center and *f* refers to foreign demand, i.e. the FBRELL. *P* is a price vector, *X* is a vector of factors shifting domestic demand, and *Y* and *Z* are vectors of factors shifting demand from FFZ24 Center and foreign demand, respectively. The parameters defined by vectors α, β and γ are for the different demand sources. Demand from FFZ24 Center and FBRELL represents both consumption and generation, whereas we are only interested in demand while estimating the total demand elasticity.

Thermal production in FFZ27 West is based on natural gas and to some extent on fuel oil. The FTS regulates the domestic gas price on a quarterly basis, whereas a relatively small share of gas is sold by independent producers mostly in the eastern part of Russia because of the limited access to Gazprom's natural gas grid. The dominant type of thermal power plant is the combined heat-and-power plant (CHP). Minimum thermal generation has a distinct seasonal profile and depends on the degree of heat experienced, i.e. the demand for heat when temperatures drop below 12–16°C. Minimum thermal generation (pmin) is a fixed value set by the SO and generation below this level is priced at zero and is a direct constraint in the SC-OPF algorithm, and thus is inelastic to price in the DAM. Since minimum generation for thermal power plants is fixed, hydro generation follows directions from the SO and ATS and nuclear generation lack the flexibility I can focus on the elastic part of the supply curve given by the flexible thermal generation above minimum.

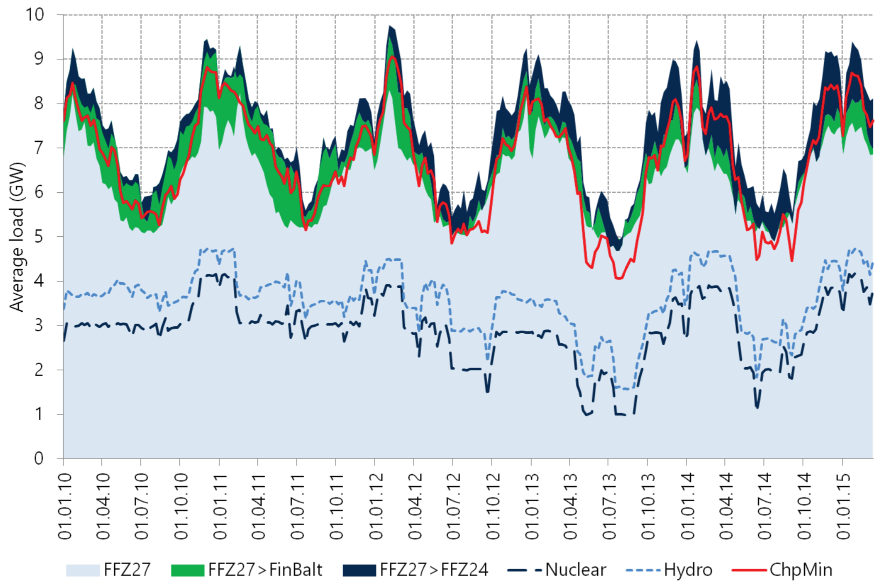

Figure 4.3 Balance in FFZ27 West

Total minimum generation in FFZ27 is represented by the red line, domestic demand and flows to other regions by areas. Nuclear and hydro generation are indicated by dotted lines.

Corts (1999) argues that the BL framework may underestimate the degree of market power, but also illustrates that the estimated conduct parameter[12] may be biased, since in the dynamic setting the firms' first order condition may also depend on incentive compatibility constraint present under collusion. Gazprom stand for 85% of installed thermal capacity in FFZ27 West and thus I assume that flexible thermal generation is represented by one market participant. Natural gas is the only technology in this formulation of the supply curve and thus is the only cost shifter for marginal costs, which deals with poor ability of NEIO technique estimating the sensitivity of marginal cost to cost shifters. Similar to Kim and Knittel (2006) I assume marginal costs to be linear in quantity. The relationship between flexible thermal generation above minimum and price in FFZ27 West illustrated in Figure 1 in Appendix 1.

[12] Corts refers to conduct parameter, i.e. λ is the mark-up parameter measuring the degree of market power, see chapter 4 for more details.

Given the arguments above, I can now focus directly on the elastic part of the supply function and residual demand that thermal power producers face in the DAM after nuclear, hydro and minimum thermal generation is taken into account, as illustrated in Figure 4.3 and Figure 4.4. The domestic residual demand that thermal generators face is defined as:

$$Q_d = D_d(P, X; \alpha) - Nuclear - Hydro - PMIN_{thermal} + \varepsilon \text{, where} \qquad (5)$$

D_d is domestic demand in FFZ27 West, *Nuclear* is nuclear power generation, *Hydro* is hydro generation and $PMIN_{thermal}$ is minimum thermal generation defined by the SO in the UC market.

The supply function can be defined as:

$$P = C(Q, W; \delta) - \lambda h(P, X, Y, Z; \alpha, \beta, \gamma) + \eta \,. \qquad (6)$$

Total demand is:

$$Q = Q_d + Q_c + Q_f \,. \qquad (7)$$

The demand (1) and supply (2) relation represent a system of simultaneous equations, where *X*, *Y*, *Z* and *W* are the vectors of exogenous variables, and demand/supply are observed endogenous variables. Thus, consistent estimation of the structural parameters (α, β, γ and δ) must take into account endogeneity in equations (1) and (2).

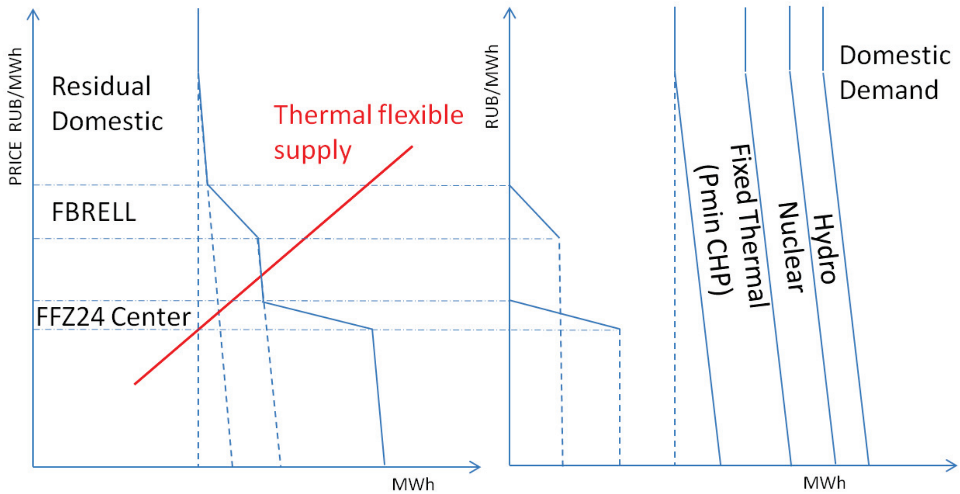

Figure 4.4 Illustration of estimation

The study is based on hourly data on actual generation by fuel type, minimum and maximum thermal generation and flows to other regions in addition to price indices for the FFZ24 Center and FFZ27 West from 1 January 2010 to 23 March 2015 downloaded from the ATS (atsenergo.ru). The average nodal price index for the FFZs is the volume-weighted average of nodal prices in the FFZs and thus will reflect the marginal offer, average loss price (relative to the reference bus) and average congestion costs in the FFZs. Daily temperature and precipitation data are available from the Hydro Meteorological Center of Russia (wmc.meteoinfo.ru). Nuclear and hydro generation, estimated reservoir balance and price data for Nord Pool, were provided by SKM Market Predictor. The regulated price for natural gas[13] is published by Federal Tariff Services (FST) and available at the Ministry of Energy of Russian Federation (minenergo.ru). Exchange rate data were downloaded from the Russian National Bank and quarterly interest rates are from the Ministry of Finance of the Russian Federation. Descriptive statistics and a full overview of the data can be found in Table 1 of the Appendix 2.

Augmented Dickey–Fuller (ADF) and Philips–Perron (PP) tests suggest that the null hypothesis of the presence of a unit root is rejected at the 5% level for all the variables except for oil and gas prices. As mentioned previously, the FTS regulates the domestic gas price on a quarterly/annual basis and thus represents step-wise increase similar to trend see Figure 2 in Appendix 1.

The supply and residual demand equations are estimated using a two-stage generalized method of moments (GMM) with heteroskedasticity and autocorrelation consistent (HAC) standard errors and an appropriate lag structure to make the estimates robust against any type of autocorrelation and heteroskedasticity. Demand from FBRELL and Center is estimated by two-stage least squares (2SLS) regression.

A residual domestic demand curve is estimated by temperature and astronomic day length in FFZ27 West, whereas all exogenous variables that shift the supply – price for fuels, thermal generation as instruments in the first stage.

[13] I convert natural gas prices in RUB/m^3 to RUB/MWh using a calorific value of 6.97 MWh/m^3 and 30% efficiency rate.

Temperature is measured by heat and cooling degrees (TempH/TempC), i.e. positive variables for deviations above or below 16°C, respectively. Demand in FFZ27 West is relatively inelastic to changes in temperature above 16°C degrees, as demonstrated in Figure 4.5.

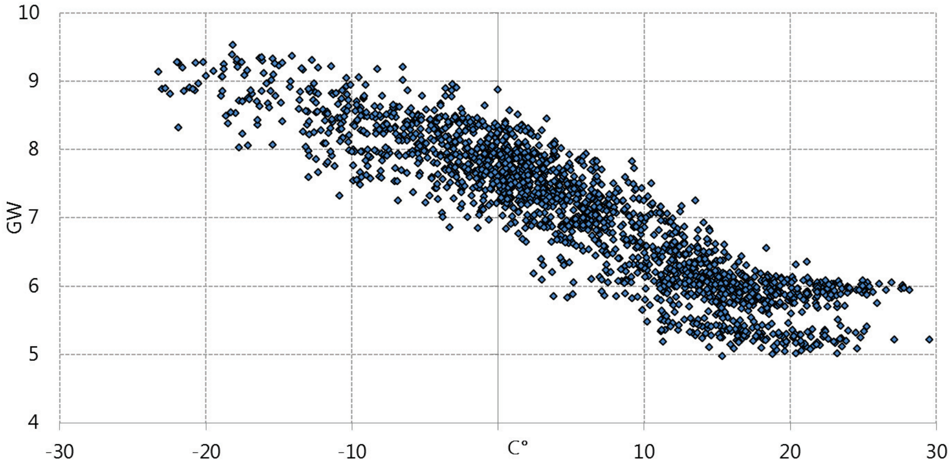

Figure 4.5 Temperature vs. consumption in FFZ27 West

The natural choice of rotation, or interaction variable, is the interaction between price and temperature, i.e. price × temperature, denoted by PriceTempH (heating) and PriceTempC (cooling). A dummy variable for working day is added to capture differences in consumption levels during the week. Rotation variables and the dummy for working day are used in all demand estimations.

Demand from FFZ24 Center is estimated by the temperature in Moscow, day length, maximum available capacity, thermal generation above pmin in FFZ24 and a trend to capture changes in the balance[14] situation between FFZ27 West and FFZ24 Center.

Demand from FBRELL is estimated using reservoir balance, hydro and nuclear generation in the Nordpool area, heating and cooling degrees in FFZ27 West, and the rotation variables. The general trend is that electricity exports from Russia decrease throughout the period, which can be represented by a trend. The introduction of the competitive pricing of capacity and decrease in electricity price in Finland led to a significant drop in exports during July 2012, as illustrated in

[14] Examples can be changes in installed capacity, long-term maintenance, differences in changes in consumption, decommissioning, etc.

Figure 4.6. Nevertheless, since summer 2012, the weekly average export volumes to FBRELL was around 400-500 MW, weekly maximum and minimum at 900 MW and -250 MW respectively. I assume that the estimation across different hours of the day and working day dummy captures the effect of capacity tariff applied on the certain hours during the day.

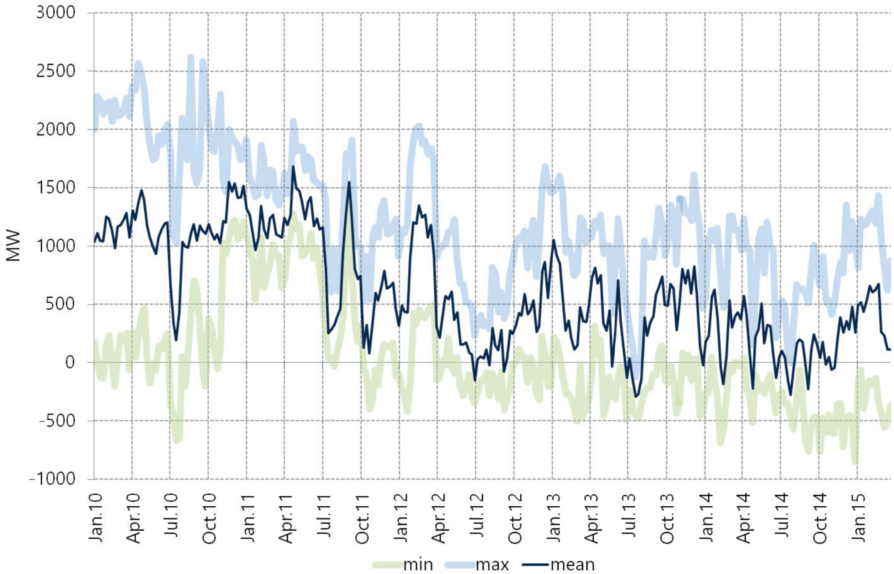

Figure 4.6 Weekly min/mean/max flows between FFZ27 West and FBRELL

For the supply curve estimation, I use thermal generation below/above pmin, hydro and nuclear generation, domestic gas price, increase in internal rate of return, trend and workday dummy. Temperature, day length, generation in Nord Pool and FFZ24 Center are used as instruments in the first-stage estimation. All instruments i demand and supply estimations are significant, indicating that instruments are relevant and pass Hansen's test of over-identifying restrictions (for most hours during the day; the first-stage estimation are available on request from the author).

5 DEMAND ESTIMATION RESULTS

The two-stage GMM estimation results for the domestic residual demand function are reported in Table 2 in the Appendix 2. The coefficient for heating degrees has a negative sign because of the increase in CHP generation during colder weather, which dominates increases in consumption because of colder weather. The cooling degrees coefficient is negative, with some variation during the day. The day length coefficient in the domestic demand estimation is negative, with its highest value in absolute terms in the morning and evening hours.

The coefficient for working day is significantly above zero for the hours between 7 am and 8 pm, and significantly below zero from midnight to 4 am. The coefficient for price in the second-stage regression is smallest for the hours between 4 am and 8 am, and highest at 9 am, midnight and 8 pm. The residual demand price elasticity is relatively flat during the day, with distinct increases in absolute value for the hours 9–10 am and 7–9 pm, which are ramp-up/down periods when rapid increases/decreases in demand are balanced by available hydro production and demand response from industry, which accounts for around 60% of consumption in FFZ27 West.

The coefficient for price in the estimation of demand for flows to FFZ24 Center is highest during peak hours, whereas flows from FFZ27 to FFZ24 are highest during the night and early morning hours. The coefficient for the temperature in Moscow has a positive sign, whereas the day length coefficient implies lower flows from FFZ27 to FFZ24 when the number of daylight hours increases. The trend coefficient is around 0.6 and is relatively stable and significant throughout the day. See Table 3 in the Appendix 2 for further details.

Demand from FBRELL is most price inelastic for the hours between 4 am and 8 am Moscow time, i.e. 2–4 am Oslo time. According to the coefficients for heating degrees, the colder it is in the Saint Petersburg region, the less power is exported to the west. An increase in the hydro balance, nuclear generation and hydro generation in the Nordpool area leads to a decrease in exports from FFZ27 West to FBRELL. See Table 4 in the Appendix 2 for further details.

6 MARKET POWER ESTIMATES

By using coefficients from the demand estimations and the average values of variables, I can calculate the price elasticity for residual domestic demand, demand from FBRELL and demand from FFZ24 Center.

$$\varepsilon_p = (\Delta Q / \Delta P) * (\overline{P} / \overline{Q}) . \qquad (8)$$

Based on whether the hourly value for the three demand regions is positive, I can calculate *h*, i.e. the rotation of the demand function as follows:

$$h\ (\bullet) = \frac{Q_d}{\alpha_p + \alpha_H * TempH + \alpha_c * TempC} + \frac{Q_c}{\beta_p + \beta_H * TempH + \beta_c * TempC} + \ldots$$
$$\ldots + \frac{Q_f}{\gamma_p + \gamma_H * TempH + \gamma_c * TempC} , \qquad (9)$$

where *d, c* and *f* denote residual domestic demand, demand from FFZ24 Center and demand from FBRELL; α, β and γ are the coefficients from the respective estimations (corrected for the difference in means as in equation 8), *H/C* denotes coefficients for the rotation variables (*PriceTempH* and *PriceTempC*) and *TempH/TempC* represents heating and cooling degrees, i.e. temperatures below/ above 16°C.

Table 5 in Appendix 2 includes estimates for the market power parameter λ as the estimated parameter for the variable *h* across different hours of the day. The coefficient λ is significantly different from zero for all hours throughout the day, except the hour 6–7 am when the coefficient value is close to 0.08. The coefficient indicates monopoly behaviour or a solution close to collusion for at least five hours during the day when the coefficient is above 70%. The value of λ exceeds 40% for 13 hours, implying an oligopoly for most hours of the day. The coefficient for CHP generation, i.e. thermal generation at minimum generation is negative for all hours except the hour 6–7 am. The coefficient for thermal generation above minimum has a positive sign; it is 0.3 on average and has the lowest values during the hours 10 am to 2 pm. Early morning between 4–7 am, for every 1 MW increase in thermal generation above the minimum, the price increases by 0.4 RUB/MWh. The coefficient for gas price is 0.9 on average for all hours with a minimum value of 0.56 and maximum of 1.14, meaning that increases in the domestic price for gas in RUB/MWh is passed directly to consumers. I included a working day dummy only in the estimation for the hours between 6 am and 4 pm and the coefficient is significantly above zero for the hours 8 am to 6 pm. Including a working day dummy in the first-stage equation leads to a failure of Hansen's test of over-identifying restrictions. Further details are available in Table 5 in the Appendix 2.

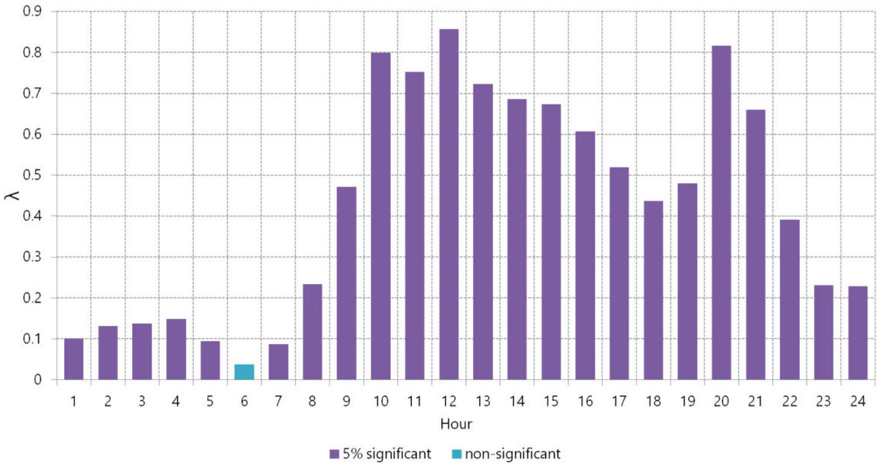

Figure 6.1 Estimated coefficients of market power index (λ in equation 6)

The mark-up can be calculated on the basis of the Lerner Index, defined as $(P-MC)/P=-\lambda/\varepsilon_p$, where ε_p is the demand price elasticity (Perloff et al. 2007). I assume that, on average, the total elasticity equals the sum of the price elasticities for every demand region for demand that thermal producers face in FFZ27 West. On average, mark-ups are slightly above zero for the night hours, when domestic residual demand is close to zero and the price is thus set by the demand from FBRELL and FFZ24 Center. In contrast, the mark-ups are above 7% between 10 am and 5 pm and at 8–9 pm. By calculating the price mark-ups based on the actual hourly data[15], the price elasticity that thermal producers face is much lower in absolute terms, which implies higher price mark-ups. The actual max/median/mean mark-ups in Figure 6.2 are calculated based

[15] For example, I include only the price elasticity of demand from FFZ24 Center if exports to FBRELL are zero (below zero) and residual domestic demand is zero (below zero, i.e. covered by CHP pmin, nuclear and hydro generation).

on whether hourly demand data are positive and represent maximum/median/minimum values for the hourly mark-ups during the analysed period. The minimum value is represented by "*Average 5% Significant*" from the estimation, because I assumed that the total demand price elasticity equals the sum of the price elasticities for all demand regions, i.e. domestic, FBRELL and FFZ24 Center.

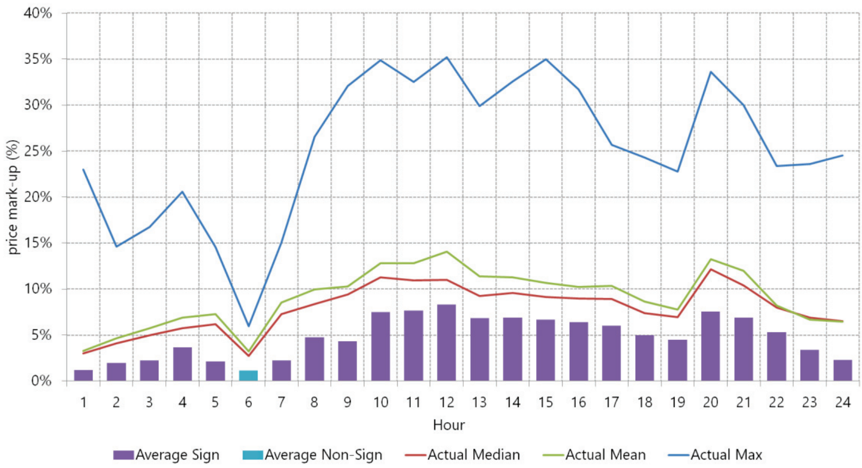

Figure 6.2 Estimated market price mark-up

Notes: Bars represent significant (purple) and non-significant estimates (blue) of the average price mark-up based on significant demand elasticity coefficients. Lines represent median, mean and maximum mark-ups based on the demand elasticity during the specific hour for the analysed period.

7 CONCLUSIONS

In this paper, I model the Northwest Russian power market to test whether the thermal producers exercise market power and assume that nuclear and hydro supply is determined by exogenous factors. Using hourly data in the Bresnahan and Lau framework, I find that price mark-ups are close to 7–8% on average for the hours between 10 am and 9 pm and 2–3% for the remaining hours. The residual demand elasticity is relatively high during peak hours, which can be explained by the fact that industry accounts for more than 60% of total demand. In addition, demand from FBRELL and FFZ24 Center have a different profile, so total demand is most elastic during peak hours and least elastic during the periods of rapid changes in consumption, i.e. 8–10 am and 7–9 pm.

The price mark-up is directly linked to the price elasticity of demand, and during the periods when exports to FBRELL or flows to FFZ24 Center are zero, the mark-up increases according to the decrease in the elasticity of demand. During these periods, the calculated maximum mark-up increases by up to 30% during peak hours when only one of the demand sources is present or 10–12% based on the actual data. The analysis illustrates also that potential mark-ups are bounded by supply in FFZ24 Center.

The domestic demand estimation illustrates the role of heat generation in Northwest Russia. Colder weather leads to higher heat generation and consequently to a decrease in residual demand, which in turn leads to a decrease in prices.

In the analysed period, an increase in natural gas prices of 1 RUB/MWh causes an increase of 0.9 RUB/MWh in Northwest Russia. The domestic prices for natural gas are expected to increase by at least 50% by 2020. Thus, one can expect similar increases in the price for electricity given that natural gas will still be the dominant fuel for electricity generation in Northwest Russia.

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APPENDIX 1. FIGURES

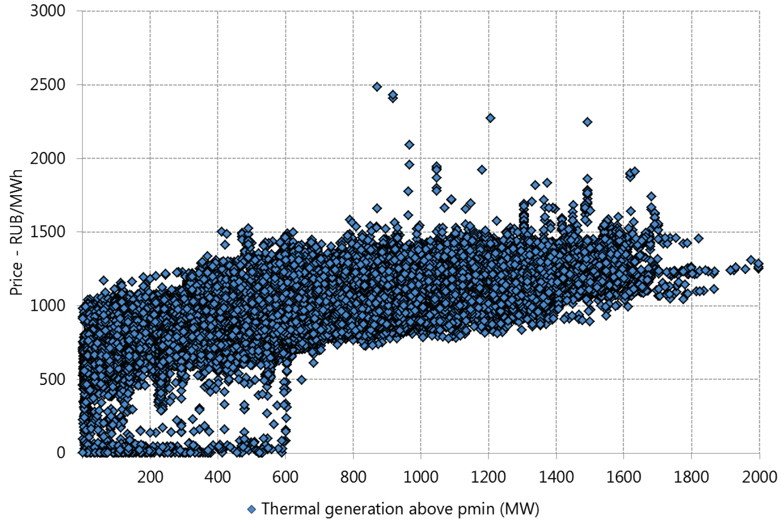

Figure 1 The relationship between price and flexible thermal generation in FFZ27 West

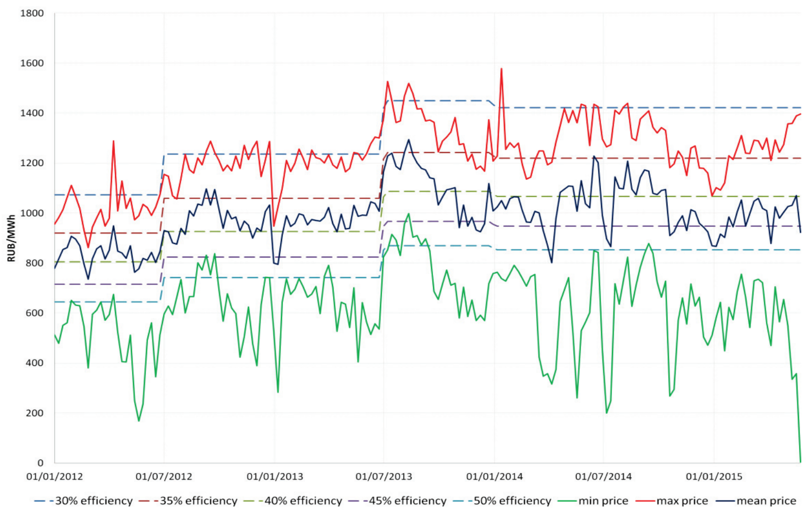

Figure 2 Weekly min/mean/max price and fuel cost for natural gas generation in FFZ27

APPENDIX 2. TABLES

Table 1 Descriptive statistics (01.01.2010 – 21.03.2015)

Daily	**Units**	**Mean**	**StdDev**	**Min**	**Max**
Brent Urals	RUB/barrel	2953	400	2091	3828
Gas Price	RUB/MWh	896	143	699	1087
Irr (100% - 2010)	%	156	15	130	184
EUR/RUB		44	8	37	85
NordPool NucGen	GW	61.1	8	23.2	66.6
NordPool Reservoir Balance	GW	-10.7	14.4	-43	11.3
NordPool WatGen	GW	35.1	8.7	11.2	57.1
Temperature FFZ24 Center	C°	6.18	11.08	-23.1	28.74
Temperature FFZ27 West	C°	5.56	10.43	-23.3	29.55
Temp FFZ27 Cooling degrees	C°	11.16	9.42	0	39.25
Temp FFZ27 Heating degrees	C°	0.73	1.98	0	13.55
Hourly:					
Flexible Thermal Generation FFZ24 Center	MW	2365	1426	-844	5988
Flexible Thermal Generation FFZ27	MW	859	478	-764	2297
Demand Center (FFZ27>Center)	MW	400	592	-1331	1900
Demand FBRELL (FFZ27> FBRELL)	MW	619	570	-853	2619
Available Flexible Thermal Gen. FFZ24	MW	3355	1501	346	7377
Available Flexible Thermal Gen. FFZ27	MW	1009	441	-238	2601
Price Difference FFZ24-FFZ27	RUB/MWh	75	116	-1389	1858
Price FFZ27 West	RUB/MWh	954	229	0	2483
Price FFZ27 West inEUR	EUR/MWh	22	6	0	59
Consumption FFZ27 West	MW	6338	1126	3864	9522
Residual Demand FFZ27 West	MW	-348	791	-2969	1860
Residual Supply FFZ27 West	MW	665	419	0	1997
Thermal Generation FFZ24 Center	GW	19.2	3.1	11.2	27.7
Thermal Generation FFZ27 West	GW	7.35	1.25	4.3	10.6
Nuclear Generation FFZ24 Center	GW	10.1	1.55	5.83	13.5
Nuclear Generation FFZ27 West	GW	2.89	0.76	0.8	4.18
Hydro Generation FFZ24 Center	GW	0.54	0.49	0.02	2.1
Hydro Generation FFZ27 West	GW	0.68	0.14	0.27	1

Table 2 Domestic Residual Demand Relation Equation

	Hour 1	Hour 2	Hour 3	Hour 4	Hour 5	Hour 6	Hour 7	Hour 8	Hour 9	Hour 10	Hour 11	Hour 12
PriceFFZ27	-1.742**	-1.101**	-0.824*	-0.339*	-0.582*	-0.357*	-0.694*	-0.657*	-2.337**	-1.708**	-1.522**	-1.294**
PriceTemp27C	0.202**	0.135*	0.0888	0.115**	0.136*	0.0701**	0.0577	0.0464**	0.123**	0.0934**	0.0824**	0.0813**
PriceTemp27H	0.252**	0.245**	0.229**	0.0832	0.277**	0.133**	0.0886	0.168*	0.363**	0.245**	0.233**	0.222**
Length Day	102	655.5*	268.8	292.8	417.5	-382.9*	-1154.3**	-1269.1**	-1332.6**	-907**	-756.5**	-674.8**
Temp27C	-195.6**	-111.7*	-80.26	-102.3**	-113.4*	-65.56**	-47.07	-51.28**	-136.6**	-105.2**	-92.68**	-92.06**
Temp27H	-253.7**	-230.4**	-218.6**	-69.55	-251.4**	-115**	-81.79	-174.5**	-415.8**	-286.7**	-269.7**	-256.6**
Nuc27	-0.495**	-0.251**	-0.183**	-0.002	0.05	0**	-0.238**	-0.322**	-0.584**	-0.574**	-0.616**	-0.597**
Wat27	-0.92**	-0.704**	-0.431*	.	.	.	.	.	-0.883**	-0.708**	-0.687**	-0.742**
Workday	-140.5**	-118.3**	-103.3**	-106.9**	-30.99	0**	110**	240.6**	661.7**	620.4**	567.9**	465.6**
Constant	3520.6**	1713.2**	1351.5**	382.3	373.9	713.6**	1790.3**	2096.8**	5044.3**	4353.3**	4316.2**	4071.4**
R-sq	43	25	20	11	.	.	9	33	23	44	51	56
Wald Chi	282.51	103.41	51.3	137.28	13.9	146.3	98.48	105.83	169.53	362.23	411.61	389.73
Root MSE	204.74	165.53	142.36	133.1	125.81	133.51	171.79	214.93	278.41	288.77	290.59	272.26
N	261	131	99	73	61	70	108	258	575	859	985	961
	Hour 13	**Hour 14**	**Hour 15**	**Hour 16**	**Hour 17**	**Hour 18**	**Hour 19**	**Hour 20**	**Hour 21**	**Hour 22**	**Hour 23**	**Hour 24**
PriceFFZ27	-1.362**	-1.401**	-1.343**	-1.301**	-1.246**	-1.181**	-1.524**	-1.741**	-1.428**	-1.091*	-1.412**	-2.564**
PriceTemp27C	0.0756**	0.0776**	0.0712**	0.0748**	0.0709**	0.0742**	0.0918**	0.117**	0.114**	0.0929**	0.103**	0.216**
PriceTemp27H	0.245**	0.214**	0.2**	0.204**	0.193**	0.207**	0.293**	0.343**	0.266**	0.178*	0.246**	0.409**
Length Day	-658.4**	-564.9*	-552.9*	-576.5*	-668**	-1036.8**	-1372.6**	-1670.1**	-1781.2**	-1545.5**	-1303.3**	-706.5*
Temp27C	-85.82**	-89.46**	-83.01**	-86.09**	-78.99**	-82.67**	-101.5**	-135.3**	-137.9**	-117.1**	-120.3**	-222**
Temp27H	-277.5**	-245**	-230.5**	-233.9**	-213.9**	-223.3**	-323.6**	-390.1**	-320**	-238.8**	-302.9**	-437.2**
Nuc27	-0.597**	-0.609**	-0.608**	-0.612**	-0.594**	-0.545**	-0.544**	-0.501**	-0.482**	-0.529**	-0.628**	-0.665**
Wat27	-0.757**	-0.806**	-0.812**	-0.882**	-0.918**	-0.801**	-0.893**	-0.91**	-0.875**	-0.993**	-0.911**	-0.909**
Workday	419**	465.6**	484.1**	457.4**	383.8**	266.8**	220**	170.3**	136.3**	97.96**	34.32	-31.23
Constant	4143.2**	4205.7**	4125.3**	4108.3**	4061.5**	4033.5**	4696.5**	5100.7**	4844.9**	4593**	4847.2**	5484.9**
R-sq	55	53	52	51	49	44	35	28	34	42	53	40
Wald Chi	384.87	378.87	387.93	356.89	286.8	222.43	232.2	190.4	194	269	542	391
Root MSE	267.81	275.28	278.21	273.71	268.61	266	274.46	287.17	285	284	252	262
N	914	923	911	870	852	874	942	938	905	852	668	434

Table 3 FFZ24 Center Demand Relation Equation

	Hour 1	Hour 2	Hour 3	Hour 4	Hour 5	Hour 6	Hour 7	Hour 8	Hour 9	Hour 10	Hour 11	Hour 12
PriceFFZ27	-0.313*	-0.807**	-0.853**	-0.843**	-0.802**	-0.768**	-0.652**	-0.847**	-1.082**	-1.357**	-1.238**	-1.305**
PriceTemp27C	0.0122**	0.0175**	0.0202**	0.0217**	0.0219**	0.0222**	0.0164**	0.0219**	0.0212**	0.0222**	0.0177**	0.0189**
PriceTemp27H	0.00844	0.0184**	0.0263**	0.0283**	0.0321**	0.0253**	0.0205**	0.0229**	0.0187**	0.0153**	0.016**	0.0137**
Temp24	12.37**	12.17**	12.31**	11.98**	11.81**	11.62**	6.84*	9.12**	14.86**	19.62**	13.59**	14.05**
Length Day	-66.5	-180.3	-299.8*	-428.6**	-547.7**	-446.1**	-394.9**	-423.3**	-633.1**	-666.4**	-517.7**	-313.6*
AvailMaxCap24	0.028	0	-0.001	0.011	0.008	0.031	0.073**	0.042	0.023	0	0.002	0.039
AboveMinCap24	-0.12**	-0.1**	-0.18**	-0.19**	-0.24**	-0.23**	-0.11**	0.07**	0.05*	0.05*	0.05*	0.07**
Trend	0.612**	0.632**	0.608**	0.595**	0.61**	0.624**	0.591**	0.576**	0.617**	0.654**	0.626**	0.664**
Constant	2.1	531.3**	661.5**	689.2**	777.1**	637.1**	468.1**	585.9**	875.8**	1117.8**	1035**	773**
R-sq	38	36	33	32	31	33	37	37	39	37	35	33
Wald Chi	901.81	899.83	841.52	842.26	851.98	963.2	1217.9	1015.92	982.55	863.99	735.55	662.46
Root MSE	333.12	354.14	360.83	369.59	376.25	368.7	377.07	372.94	350.96	345.23	342.87	358.62
N	1369	1477	1516	1532	1548	1558	1555	1537	1491	1420	1354	1321
	Hour 13	**Hour 14**	**Hour 15**	**Hour 16**	**Hour 17**	**Hour 18**	**Hour 19**	**Hour 20**	**Hour 21**	**Hour 22**	**Hour 23**	**Hour 24**
PriceFFZ27	-1.263**	-1.033**	-0.918**	-0.967**	-1.128**	-1.036**	-1.156**	-1.338**	-1.253**	-0.765**	-0.486**	-0.594**
PriceTemp27C	0.0183**	0.015**	0.00844**	0.00538	0.00447	0.00548	0.00286	0.00667*	0.00723*	0.00243	0.00192	0.00758*
PriceTemp27H	0.00147	-0.00109	0.00639	0.0123**	0.00614	0.00704	0.00623	0.0062	-0.00048	0.00037	0.0088*	0.0129*
Temp24	14.7**	13.34**	7.5*	5.84	4.23	0.62	-1.67	0.73	2.86	3.76	5.88*	10.15**
Length Day	24.5	49.9	-85.8	-377**	-413.5**	-359.3**	-403.1**	-331.8*	-302.5*	-164.6	112.6	304.7*
AvailMaxCap24	0.044	0.03	-0.005	0.007	0.034	0.06*	0.033	0.014	0.017	-0.009	0.019	0.055*
AboveMinCap24	0.05*	0.02	-0.01	0.01	0.06*	0.03	0	0.01	0.02	-0.06*	-0.15**	-0.13**
Trend	0.663**	0.591**	0.538**	0.531**	0.581**	0.613**	0.635**	0.675**	0.686**	0.547**	0.554**	0.636**
Constant	589.1**	573.8**	863**	1021.9**	996.8**	872.4**	1188.1**	1261.6**	1105.3**	912.7**	491.3*	42.07
R-sq	33	29	26	27	31	32	30	29	30	27	36	36
Wald Chi	655.86	537.76	464.09	512.89	531.72	660.72	577.43	546.08	542.15	463.1	720.74	853.43
Root MSE	335.91	333.52	327.12	335.87	363.73	362.36	358.31	361.26	364.75	318.91	303.77	319.65
N	1299	1286	1290	1307	1283	1285	1298	1294	1288	1208	1169	1243

Table 4 FBRELL Demand Relation Equation

	Hour 1	Hour 2	Hour 3	Hour 4	Hour 5	Hour 6	Hour 7	Hour 8	Hour 9	Hour 10	Hour 11	Hour 12
PriceFFZ27	-2.782**	-2.559**	-2.319**	-2.351**	-1.115**	-0.841**	-0.567**	-1.37**	-2.226**	-2.78**	-2.553**	-3.086**
PriceTemp27C	0.0865**	0.0819**	0.088**	0.11**	0.0479**	0.0206	0.00457	0.0364**	0.076**	0.0916**	0.071**	0.107**
PriceTemp27H	0.372**	0.353**	0.33**	0.316**	0.159**	0.159**	0.136**	0.266**	0.343**	0.424**	0.403**	0.515**
Temp27C	-60.9**	-46.4**	-44.1**	-56.6**	-12	4.2	13.8	-22.3	-66.7**	-90.4**	-71.8**	-110**
Temp27H	-339.7**	-286.5**	-240.2**	-211.6**	-99.1**	-108.9**	-101.4**	-244.2**	-345**	-468.1**	-463.5**	-591.9**
NordPool Reservoir Balance	-0.01**	-0.01**	-0.01**	-0.01**	-0.01**	-0.01**	-0.01**	-0.01**	-0.02**	-0.02**	-0.01**	-0.01**
NordPool NucGen	-0.014**	-0.016**	-0.017**	-0.015**	-0.014**	-0.016**	-0.014**	-0.011**	-0.011**	-0.011**	-0.009**	-0.008**
NordPool WatGen	-0.0136**	-0.0138**	-0.0134**	-0.0127**	-0.0094**	-0.0103**	-0.0127**	-0.0118**	-0.0077**	-0.0067**	-0.0079**	-0.0077**
Constant	4350.8**	4002.6**	3691.3**	3483.8**	2450**	2385.3**	2128**	2673.5**	3468.5**	4215.7**	4018.8**	4545.9**
R-sq	22	24	21	16	27	31	33	29	21	22	28	20
Wald Chi	1074.96	1184.03	1010.27	876.62	932.32	1145.14	1300.17	1375	1225.65	1213.49	1208.03	999.13
Root MSE	408.53	421.68	432.81	440.5	407	382.27	360.37	368.09	400.29	402.88	385.03	401.71
N	1592	1585	1582	1570	1566	1563	1511	1427	1301	1207	1176	1198
	Hour 13	**Hour 14**	**Hour 15**	**Hour 16**	**Hour 17**	**Hour 18**	**Hour 19**	**Hour 20**	**Hour 21**	**Hour 22**	**Hour 23**	**Hour 24**
PriceFFZ27	-3.303**	-3.157**	-3.301**	-2.951**	-2.337**	-2.568**	-2.879**	-2.615**	-2.518**	-2.06**	-1.828**	-2.202**
PriceTemp27C	0.119**	0.117**	0.126**	0.11**	0.0721**	0.0904**	0.102**	0.0892**	0.0789**	0.0557**	0.0486**	0.0698**
PriceTemp27H	0.551**	0.454**	0.48**	0.425**	0.352**	0.397**	0.446**	0.404**	0.342**	0.272**	0.248**	0.307**
Temp27C	-119.4**	-118**	-129.5**	-113.1**	-72.7**	-90.9**	-101**	-86**	-74.2**	-46.3**	-33.5*	-52.2**
Temp27H	-624.6**	-527.9**	-552.2**	-489.1**	-406.3**	-437.1**	-483.1**	-437.3**	-369.9**	-309.7**	-272.2**	-302.6**
NordPool Reservoir Balance	-0.01**	-0.01**	-0.02**	-0.02**	-0.02**	-0.02**	-0.02**	-0.02**	-0.01**	-0.01**	-0.01**	-0.01**
NordPool NucGen	-0.008**	-0.009**	-0.01**	-0.011**	-0.013**	-0.012**	-0.009**	-0.01**	-0.013**	-0.016**	-0.016**	-0.015**
NordPool WatGen	-0.007**	-0.006**	-0.007**	-0.010**	-0.011**	-0.0117**	-0.012**	-0.012**	-0.016**	-0.012**	-0.01**	-0.009**
Constant	4701.3**	4656**	4908.2**	4669.6**	4159.7**	4338.8**	4445.4**	4227.6**	4419.3**	4064.6**	3710.6**	3850.6**
R-sq	24	27	25	27	28	26	26	26	28	29	27	22
Wald Chi	1085.33	1264.2	1366.56	1556.7	1343.2	1296.46	1328.93	1212.59	1274.94	1199.85	1177.97	1147.38
Root MSE	398.95	391.86	398.64	396.83	393.15	400.62	401.7	402.8	395	378.37	386.98	393.9
N	1268	1302	1356	1377	1348	1305	1304	1274	1278	1541	1562	1583

Table 5 Supply Relation Equation

	Hour 1	Hour 2	Hour 3	Hour 4	Hour 5	Hour 6	Hour 7	Hour 8	Hour 9	Hour 10	Hour 11	Hour 12
h	0.1*	0.131*	0.138*	0.149**	0.095**	0.038	0.087**	0.234**	0.471**	0.799**	0.752**	0.857**
SupplyRes27	0.27**	0.27**	0.3**	0.36**	0.39**	0.42**	0.41**	0.26**	0.24**	0.22**	0.22**	0.21**
SupplyChp27	-0.073**	-0.05**	-0.048**	-0.055**	-0.034	0.004	0.029	-0.033*	-0.058**	-0.08**	-0.078**	-0.087**
Wat27	-0.029	-0.024	0.013	0.018	0.002	0.011	-0.016	-0.021	0.02	-0.04	-0.049	-0.056
Nuc27	-0.016	-0.03*	-0.033*	-0.028	-0.02	-0.004	0.01	-0.008	0.005	-0.006	-0.014	-0.019
GasPrice	0.83**	0.61**	0.56**	0.79**	0.78**	0.64**	0.81**	0.97**	0.97**	0.89**	0.86**	0.88**
irr	29**	30**	31**	30**	30**	38**	40**	26**	17**	16*	18*	13
Trend	-0.99**	-0.97**	-1**	-1.07**	-1.05**	-1.26**	-1.4**	-0.96**	-0.62**	-0.51**	-0.53*	-0.39
Workday	.	.	.	.	.	2.333	12.32	102**	114.9**	122.3**	109.8**	104.8**
Constant	-3339**	-3328**	-3421**	-3538**	-3515**	-4688**	-4975**	-3091**	-1894*	-1623	-1767	-1108
R-sq	52	52	38	30	26	31	32	46	51	53	51	43
Wald Chi	265.52	703.19	412.4	229.38	251.36	324.79	420.39	755.25	577.72	595.18	603.91	417.46
Root MSE	93.518	94.319	121.75	147.7	158.82	150.99	150.37	131.67	123.48	116.27	118.58	126.79
	Hour 13	**Hour 14**	**Hour 15**	**Hour 16**	**Hour 17**	**Hour 18**	**Hour 19**	**Hour 20**	**Hour 21**	**Hour 22**	**Hour 23**	**Hour 24**
h	0.723**	0.686**	0.673**	0.607**	0.519**	0.437**	0.48**	0.816**	0.66**	0.391**	0.231**	0.229**
SupplyRes27	0.2**	0.21**	0.24**	0.31**	0.3**	0.31**	0.32**	0.31**	0.29**	0.32**	0.31**	0.24**
SupplyChp27	-0.081**	-0.09**	-0.091**	-0.053**	-0.05**	-0.038**	-0.033**	-0.06**	-0.066**	-0.049**	-0.049**	-0.077**
Wat27	-0.071	-0.048	0.003	0.096	0.041	0.016	0.013	-0.047	-0.078	-0.07	-0.031	-0.045
Nuc27	-0.023	-0.016	-0.003	0.067**	0.056**	0.064**	0.068**	0.038**	0.037**	0.04*	0.037	-0.003
GasPrice	0.82**	0.84**	0.95**	1.11**	1.14**	0.96**	0.99**	1.02**	1.02**	0.96**	1.05**	0.96**
irr	16*	16*	13	11*	15**	12*	12*	20**	18*	23**	22**	20**
Trend	-0.49*	-0.49*	-0.43*	-0.33*	-0.47**	-0.34**	-0.37**	-0.61**	-0.57**	-0.67**	-0.72**	-0.74**
Workday	91.24**	106.3**	99.7**	57.54**	56.13**	43.28**	.	.	.	.	.	.
Constant	-1537	-1544	-1337	-1540*	-1957**	-1528**	-1659**	-2414**	-2027*	-2766**	-2779**	-2160*
R-sq	46	45	46	49	52	49	54	50	48	54	49	49
Wald Chi	460.21	449.25	444.27	481.42	470.75	362.79	426.98	291.58	257.27	372.3	285.48	339.75
Root MSE	117.71	125.95	130.6	126.61	115.73	121.93	114.44	118.61	116.86	117.81	122.89	107.29

Paper 3

MARKET RULES AND MARKET POWER IN THE RUSSIAN ELECTRICITY AND CAPACITY MARKET

Abstract

The purpose of this article is to study market power in the Russian power markets by adjusting the traditional Herfindahl–Hirschman index (HHI) and residual supply index (RSI) to reflect the market rules for the respective markets. Hydro power plants cannot offer prices, and thus exert market power directly, which is crucial for the electricity and capacity markets in Russia. In addition, minimum generation constraints reduce the potential for market manipulation in the day-ahead market. The adjusted HHI and RSI are significantly below the values reported in the existing literature. Nevertheless, by applying the transmission-constrained RSI (TCRSI), I show that there exists a significant number of pivotal firms in the majority of the free-flow zones (FFZs). There exists a strong relationship between price/price–cost mark-up and the TCRSI where decreases in the TCRSI are correlated with increases in the price/price–cost mark-up.

Key words: Russian power market, market power, electricity, RSI, HHI, TCRSI

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1 INTRODUCTION

Russia is in the process of one of the most ambitious electricity reforms ever undertaken, liberalizing a one-thousand TWh market by splitting the state-owned holding company RAO UES into 24 territorial generating (TGK) and wholesale generating (OGK) companies (for details on the reform itself, see Cooke (2005) and Abdurafikov (2009)).

The overall consensus in the literature (Cooke 2013; Gore et al. 2012; Chernenko 2015) is that when transmission constraints are taken into account, the Russian power market is dominated by a few large players with the potential to exhibit market power. However, none of the articles take into account the specific formulation of the clearing algorithm at the power plant level, which have direct impacts on the ability of dominant power producers to exert market power.

The objective of this paper is to take into account the market rules of the day-ahead market (DAM), unit commitment (UC) auctions and capacity market (CM) in the calculation of the concentration measures. The results suggest that market rules constrain the ability of producers to exert market power in the DAM, but find a high concentration in UC auctions and the CM.

Furthermore, I investigate the role of transmission constraints through the transmission-constrained residual supply index (TCRSI) in a zonal market clearing formulation based on free-flow zones (FFZs) for the 35 largest generators in terms of average available and flexible capacity. The strong correlation between the TCRSI and price/price–cost mark-up in the FFZs does not imply causality, but rather suggests that there is a close relationship between increases in price and increases in the dominant position of market participants in the analysis. Overall, the results imply that market power decreases as the share of hydro producers increases and as the transmission capacity to the neighbouring regions increases in the Russian power market; in addition, it also depends on the share of flexible generation in the DAM.

The paper is organized as follows. Section 2 discusses the traditional market power indices. Section 3 describes the Russian power market and the regions for further analysis. In Section 4, I present the adjusted concentration indices that reflect the market rules in the Russian power market. Modelling of the TCRSI is presented in Section 5, while Section 6 presents the estimation results of the relationship between the TCRSI and price/price–cost mark-up. Section 7 summarizes the main findings and concludes.

2 Traditional Market Power Indices and Measures

The Russian Federal Antimonopoly Services (FAS) does not define market power explicitly, but the term “price manipulation” in the context of the wholesale electricity market is well-defined in the Federal Law on Electricity (FL-35, 2003). Price manipulation in the wholesale electricity and capacity market is defined as: committing economically or technologically unjustified actions, including using its dominant position in the wholesale market, which leads to a significant change in prices (price) for electric energy and (or) capacity in the wholesale market. Similar to regulators in other electricity markets, the FAS focuses on a particular identified action or “exercise” of market power.

In economic theory, the definition of market power is slightly different, typically defined as the ability to profitably alter prices away from competitive levels (Stoft, 2002).The profitability requirement in the definition above implies that one would need to know the complete portfolio position of the company in to order to identify market power.

An overview of market demand and supply, costs of all power plants and transmission capacity/congestion is necessary to identify whether a company’s behaviour is intentional and whether higher prices can be explained by scarcity of supply in a well-performing competitive market (Twomey et al. 2005).

Thus, the existent research focuses on whether a company is dominant and has market power and/or whether prices deviate from competitive levels. Vassilopoulos (2003) describes four basic techniques for measuring market power: concentration measures, Lerner Index, simulation models and econometric models.

The traditional Herfindahl–Hirschman index (HHI) is formulated as the sum of squared shares (s) of each power plant in the area:

$$HHI = \sum_{i}^{N} s_i^2 = \sum_{i}^{N} \left(g_i / \sum_{i}^{N} g \right)^2 , \tag{1}$$

where g_i is available capacity of generator *i* and *N* is the set of all firms in the area. Cooke (2013) uses the scale developed by the European Union that classifies HHI with scores of 750–1800 as indicative of moderate concentration, scores of 1800–5000 as indicative of high levels of concentration, and scores above 5000 as indicative of very high concentration and consistent with the presence of substantial potential market power. The US Federal Energy Regulatory Commission considers a HHI value above 1800 as indicative of very high concentration.

The few existing studies on market power issues in the Russian power market are based on market concentration indices, like HHI. Kurronen (2006) reports a HHI value of 860 for the Russian power market, which indicates quite diversified ownership. Solanko (2011) states that if inter-regional transmission lines have no spare capacity, the heating season is likely to bestow considerable market power. Pittman (2007) focuses on HHIs for the different unified energy systems (UESs) and finds a seasonal variation in concentration. Cooke (2013) presents estimates of the HHI in the range 1162 (1381) to 3305 (3771) with (without) trade between the UESs[1]. Gore et al. (2012) and Chernenko (2015) analyse concentration in the FFZs and conclude that transmission constraints lead to the appearance of isolated markets with high generation concentration, while strong government involvement in the sector and concentrated ownership/cross-ownership structures do not support competition.

Cournot models are widely used in studies of market power (e.g. Borenstein et al. 2002; Joskow & Kahn 2002; Puller 2007). Such models are typically based on the assumption that market power is related to the degree of concentration. This relationship can be described as LI= HHI/ε, where LI is the weighted average Lerner Index and ε is the absolute elasticity of market demand with respect to price. Following the Cournot oligopoly model of Newbery (2008), firm *i* maximizes profit $\pi_i = pq_i - C_i(q_i)$, for which the first-order condition is:

$$\frac{d\pi_i}{dq_i} = 0 = p - C_q^{'} - p\left(\frac{q_i}{Q}\right)\left(-\frac{Qdp}{pdQ}\right), \qquad (2)$$

where demand, $Q = \sum q_j$, is a function of price, *p*, and $C_i^{'}(q_i)$ is the marginal cost of firm *i*. The Lerner Index can be expressed as:

[1] The value of 1800 is typically considered as the threshold for moderate concentration.

$$LI_i \equiv \frac{p - C_i^{'}}{p} = \frac{s_i}{\varepsilon} = \frac{q_i / Q}{\varepsilon} . \qquad (3)$$

The Lerner Index is directly proportional to the market share of a firm and inversely proportional to the elasticity of demand. Meanwhile, the combination of low demand elasticities with a small number of competing firms (high HHI) would suggest a very high Lerner Index and an improbably high ratio of profits to revenue (Newbery 2008).

Brennan (2002) argues that the primary context in which market power might be exercised is when the industry is facing capacity constraints. With variation in demand and transmission capacity constraints, the estimation of marginal cost for the marginal unit becomes virtually impossible.

Nevertheless, it is possible to define a pivotal generator, i.e. if there is competition to supply the last marginal MWh to cover demand in the region. The residual supply index (RSI) for a given company is equal to the total supply of available capacity in the market less the available capacity of the given company, divided by the total demand:

$$RSI_{i,t} = \frac{Total\ Supply_t - g_{i,t}}{Total\ Demand_t} , \qquad (4)$$

where $g_{i,t}$ is the generator capacity at time t.

$$LI_i = \frac{p - C_i}{p} = \frac{1 - RSI_i}{\varepsilon} \qquad (5)$$

The RSI has been used widely in the literature (Baldick and Hogan 2006; Borenstein et al. 2006; Newbery 2008; Bataille, Steinmetz, and Thorwarth 2014; Alberta Market Surveillance Administrator 2012; Swinand, Scully, and Ffoulkes 2010) to estimate periods when generators have market power and examine the correlation between the LI and RSI, i.e. show that an increase in price above the competitive level is correlated with periods when dominant players have market power. The rule of thumb presented by Sheffrin (2002) states that the RSI should be above 1.1 for 95% of the time to avoid market power.

Newbery (2008) shows that in the presence of forward contracts, i.e. a reduction of available capacity for spot trading, there is a significant limit to a firm's ability and reduced incentives to execute market power. This effect is not clear from the LI or

HHI in their traditional formulations, but is obvious in the RSI because it increases when available capacity for spot trade decreases. Thus, the primary goal in calculating concentration measures is to identify the available flexible capacity for pivotal generators.

This article combines adjusted concentration measures to take into account the specifics of the Russian power market, a zonal model to calculate the TCRSI and estimation of the relationship between TCRSI and price–cost mark-up (PCMU), which is closely related to the LI.

3 Description of Russian Power Market

Electricity systems need to be planned over both the long term and the short term. The Russian power market is constructed in such a way that separate markets deal with different time periods. The SO operates the one-hour-head balancing market before delivery, whereas the Administrator of Trading Systems (ATS) clears the mandatory DAM. The voluntary three-day-ahead UC auctions aim to maximize social welfare by specifying the necessary power reserves to meet demand, taking into account maintenance and unplanned outages in transmission or generation. The annual capacity market handles market planning one year ahead and long-term generation capacity. The financial market represented by the Moscow Energy Exchange (MOSENEX) accommodates bilateral trading in capacity and electricity month-ahead contracts and monthly electricity futures. Month-ahead futures for hub prices[2] have been traded consistently since the launch of the exchange, but the traded volumes represent only a small fraction of the physical market[3].

The clearing mechanism in the market is the objective function and the set of constraints with certain characteristics which can be more or less attractive for dominating market participants. It is discussed and illustrated in Harvey and Hogan

[2] Hub is defined as the number of nodes with high correlation between nodal prices and small differences in absolute values; see www.mosenex.ru/eng.

[3] The interest in bilateral capacity contracts has been modest since the launch in 2011 and no trades have been registered in 2015 so far (May 2015) on the MOSENEX. No trades for bilateral contracts for energy have been registered since January 2014. Since May, the 2014 maximum monthly trading volume has not exceeded 250 million RUB and since September 2014, the turnover has dropped to below 50 million RUB/month or some 2–8% of the DA spot market.

(2000), Holmberg and Lazarczyk (2012) and Björndal, Gribkovskaia, and Jörnsten (2014) as to why nodal pricing is less favourable for a monopolist compared with zonal pricing. Russian electricity markets are cleared by nodal pricing, whereas capacity markets are cleared by zonal pricing.

The Russian day-ahead market is formulated as a social welfare maximization problem in a security-constrained optimal power flow problem (SC-OPF), i.e. including a constraint on active and reactive power flows[4] and balances, ramp-up/down constraints, and minimum and maximum generation levels. In addition, the integral constraint for generation over a 24-hour period is applied to thermal and hydro generators if daily fuel/water consumption is constrained. Thermal and nuclear generators are allowed to offer three price–volume pairs above minimum and below maximum generation (pmin/pmax)[5], which is calculated by the SO in the UC auctions or given by the technological characteristics of the power plants.

The ATS solves the SC-OPF problem with approximately 8000 nodes and 12 000 power lines for 24 hours of the day because of the integral constraint and ramp-up/down constraint on generation. Nodal prices are dual values on the balancing constraint including shadow prices on transmission and price of losses. The objective function and the main constraints are presented in Model 1 in Appendix 2. See Davidson et al. (2009) for more details.

The SO runs three-day-ahead SC-OPF (N-1) UC auctions, where in addition to the DA market problem, one needs to take into account reserves, i.e. start/stop costs to meet expected demand and reserves and reduce total costs for the system. The participating generators offer price–volume pairs for electricity generation, but also start-up costs. The dual value on the balancing constraint in the UC auctions represents the total costs of covering demand at each node, including start/stop costs and security constraints in addition to the constraints from the ATS clearing mechanism described above. The minimum and maximum constraints for generation

[4] Active and reactive power flows are defined using non-linear equations that incorporate Kirchhoff's circuit laws.
[5] Formally six bids, where three bids are at volumes below pmin and a price close to zero, and three bids are significantly above zero and a volume above pmin. The market algorithm will correct bids if these are specified incorrectly, whereas the clearing algorithm will in practice set a zero price for all bids below pmin.

are based on the technical characteristics of the generators and technology. The generator constraints in the DAM are set based on the solution of the UC auctions, whereas offers submitted in the UC auctions are used as price caps for the offers submitted by these generators in the DAM. See Davidson and Seleznev (2014) for more details on the UC auctions and Pogrebnyak (2007), Abdurafikov (2009) and Gore et al. (2012) for details on the Russian power market in general.

Hydro resources are regulated by the Ministry of Transport and the Ministry of Natural Resources and Environment. Thus, the optimization of hydro generation is constrained by transportation and environmental interests, whereas the remaining flexibility is used by the SO to balance the system in the UC auctions and by the integral constraint for hydro generation during each 24-hour period by the ATS[6]. Hydro generators are not allowed to offer price–volume pairs and in fact report only daily available generation. Consequently, in the best-case scenario, hydro generators can offer daily available volumes, whereas hourly production is subject to the clearing mechanism, i.e. available hydro production is used to maximize social welfare. Nevertheless, the fact that the problem is solved for 24-hour periods implies that the dual value on the integral hydro generation constraint represents the water value[7] during the day. This ensures that available hydro reserves are used to maximize social welfare subject to other constraints and reduces the effect of, for example, ramp-up/down constraints on generation. The poor flexibility of power generation in Russia and its effects on prices have been previously described in Pipkin (2014).

Annual capacity auctions are cleared through zonal pricing based on the FFZs defined by the SO as zones without major transmission constraints. Based on the peak demand forecast, the available information about installed capacity and description of the grid, the SO also calculates constraints for the exchange between the FFZs and clears the market based on the offers from generators.

The FAS has been active in setting price caps on annual capacity auctions in most of the FFZs because of the dominant position of a few large generators, which could

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[6] The integral constraint is applied on generators that have constraints to their daily fuel/water use, as do, for example, gas and hydro generators.
[7] Water value is a well-established term in the Nord Pool market, and represents the alternative or potential profits of storing the water; see www.sintef.no for more details.

exert market power because of poor transmission capacity between the zones. FAS defines dominant generators as having a market share above 20%. If the technical characteristics of a generator constrain its ability to exert market power, the 20% rule can be ignored. Both the ATS and the Market Council[8] are obliged to report cases of suspicion of market power abuse to the FAS. Most cases are related to market entrance (i.e. grid issues), but price manipulation cases in the DAM from both generators and consumers have also been pursued by the FAS.

Consequently, the main distinction in the analysis of the Russian power market must be made based on the available non-hydro generation above the minimum constraint. The solution for the capacity market and the UC auctions must take into account whether or not power plants will generate electricity, i.e. whether they are running or not, whereas in the DAM the majority of the generation is fixed based on the security constraints in the UC auctions or the technological constraints of the power plant. For further discussion, I reduce the analysis to two markets—one where full capacity is available for profit maximization, and a constrained case where most of the capacity is fixed. Similar to the FAS, I focus strictly on the market participants defined by the ATS ignoring, for example, that "Lukoil" owns "Lukoil Kuban Energo", "Lukoil Astrakhan Energo" and "Lukoil Volgograd Energo" or any other types of cross-ownership[9].

The Russian power market is divided into the European and the Siberian price zones, with six UESs[10] and 21 FFZs at present. The Siberian zone consists of only one UES, Siberia, whereas the European zone includes UES Ural, UES Volga, UES South, UES Center and UES Northwest. Figure 3.1 illustrates the relationship between the UESs (solid colour) and FFZs (numbers in circles). The UESs consist of regional energy-systems and borders are based on the grid rather than federal subject (oblast). Similarly, FFZs are defined by the SO based on the transmission constraints calculated in the SC-OPF model and thus ignore energo-systems or any administrative

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[8] NP "Market Council" is a non-profit partnership between market participants (both generators and consumers) to stimulate implementation of a functioning market; for more details see www.en.np-sr.ru.
[9] The issue of cross-ownership, vertical integration and the involvement of the government are well-described in Gore et al. (2011). Gazprom Bank has significant interests in OGK-1 and OGK-3, whereas Gazprom has 50% shares in TGK-1 and TGK-3, and in addition a 35% share in Gazprom Bank.
[10] Far-East UES is not part of the day-ahead ATS power market, and the same applies to the Komi/Arkhangelsk and Kaliningrad regions.

definitions. The existence of the transmission constraints can obviously divide the FFZs into many smaller areas, but this is ignored in the capacity market. Further analysis is based on hourly data for planned, available/maximum and minimum generation for all generators, consumption in the FFZs, UESs and price zones from the ATS from 1 January 2012 to 1 June 2015.

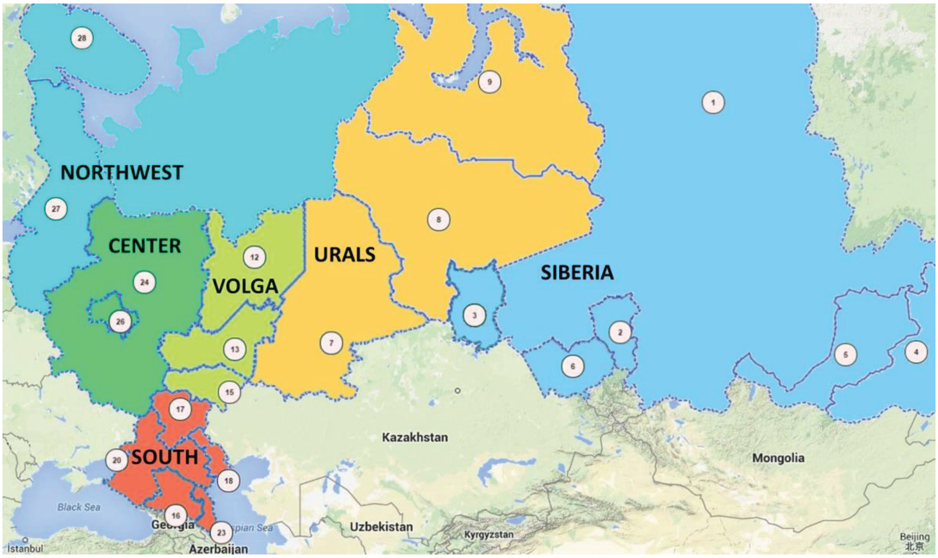

Figure 3.1 UESs and FFZs in the Russian power system

UES Siberia (Siberia-1, Kuzbass-2, Omsk-3, Chita-4, Buryatiya-5 and Altay-6), UES Ural (Ural-7, Tyumen-8, North Tyumen-9), UES Volga (Vyatka-12, Volga-13 and Balakovo-15), UES South (Kavkaz-16, Volgograd-17, Kaspiy-18, Kuban-20 and Mahachkala-23), UES Center (Center-24 and Moscow-26) and UES Northwest (West-27 and Kolskaya-28).

As can be seen in Table 3.1, the average available hourly capacity in Siberia is one-third of the capacity in the European price zone and the ratio of consumption to available capacity is also smaller. Hydro generation dominates in Siberia, whereas thermal power plants account for the majority of power produced in the European zone. Hydro generation in Siberia also accounts for the largest share of flexible generation. Flexible thermal power plants (there are no nuclear power plants east of the Urals) in Siberia represent only 11% of total available capacity in the zone on average. The remaining thermal generation is fixed, i.e. 89% (55% hydro + 34% thermal) of available generation is priced implicitly at zero. Similarly, only 21% of available generation in the European zone is flexible and can make offers above zero. It is worth mentioning that even if flexible hydro generation is priced at zero, the dual variable of the integral constraint on daily generation for hydro power plants represents the water value of the flexible hydro resource during the 24-hour clearing period.

Table 3.1 Price zone metrics as a share of maximum generation

Price zone	Maximum generation (MW)	Average hourly consumption	Non-hydro generation	Hydro generation	Flexible non-hydro generation	Flexible hydro generation
1 Europe	100 318	84%	87%	13%	21%	12%
2 Siberia	29 628	77%	45%	55%	11%	42%

Non-hydro generation includes nuclear and thermal power plants. Flexible generation corresponds to the capacity above minimum generation. Average hourly consumption refers to load in the zone.

Table 3.2 shows that, on average, non-hydro generators represent 95% and 96% of maximum available generation in UES1 Ural and UES5 Center, respectively, whereas flexible non-hydro represents 30% and 21%, respectively. In contrast, in UES4 Northwest, the apparently dominating position of non-hydro producers is only 12% of flexible generation because of the large share of nuclear generation. Flexible hydro resources in UES4 Northwest dominate over flexible non-hydro resources and thus reduce the market power of non-hydro generation.

Table 3.2 UES metrics as a share of maximum generation

UES	Maximum generation (MW)	Average hourly consumption	Non-hydro generation	Hydro generation	Flexible non-hydro generation	Flexible hydro generation
1 Ural	32 009	89%	95%	5%	30%	4%
2 Volga	15 238	78%	74%	26%	14%	25%
3 South	12 124	78%	66%	34%	18%	31%
4 Northwest	10 426	74%	79%	21%	12%	17%
5 Center	30 545	83%	96%	4%	21%	4%

Non-hydro generation includes nuclear and thermal power plants. Flexible generation corresponds to the capacity above minimum generation. Average hourly consumption refers to load in the UES. UES Siberia corresponds to Price Zone 2 in Table 3.1 and is not reported in Table 3.2.

When it comes to the FFZs, the differences are even more distinct. The five smallest FFZs (FFZ2–FFZ6) in Siberia represent one-sixth of maximum generation in Siberia and do not have any hydro resources. So, in the case of congestion, the price in these FFZs will be set only by thermal generation. In contrast, the Kolskaya nuclear power plant in FFZ28 Kolskaya (Northwest UES) accounts for more than 40–45% of available generation, but has no flexibility to set prices on average. Non-hydro generation accounts for 92% of maximum generation in the largest FFZ24 Center, whereas flexible non-hydro generation accounts for only 16% of maximum generation, i.e. 83% of non-hydro generation is fixed at the minimum constraint on average. Combined flexible and total hydro generation represent only 8% of maximum available generation in FFZ24 Center. See Table 1 in Appendix 1 for details on FFZs.

4 ADJUSTED HH AND RS INDICES

Hydro power plants follow a prescheduled production plan, whereas the flexibility in hydro generation is used to maximize social welfare in UC auctions and in the DAM. Thus, only non-hydro power plants are relevant when one calculates the HHI and only the shares of non-hydro generation owners are relevant, defined as HHI* in equation 6.

$$HHI^{*} = \sum_{i}^{I} s_i^2 = \sum_{i}^{I} \left(g_i^{*} / \sum_{j}^{N} g_j \right)^2, \tag{6}$$

where $g*$ is non-hydro generation for firm i. The HHI* shows the concentration of firms that can potentially exert market power as a share of total supply available.

Nevertheless, this adjustment is not sufficient, as most of the generation capacity is fixed in advance to minimum generation levels in the UC auctions. If demand is below the sum of total minimum generation, the price in the system will be zero.

$$HHI^{**} = \sum_{i}^{I} s_i^2 = \sum_{i}^{I} \left((g_i^{*} - g_i^{*\min}) / (\sum_{j}^{N} g_j - g_j^{\min}) \right)^2, \tag{7}$$

where $g^{*\,min}$ is minimum non-hydro generation for firm i. The HHI** reflects the concentration of thermal and nuclear generation above the minimum as a share of total flexible generation including hydro capacity. The index illustrates the concentration relevant for analysing the residual supply and demand corrected for minimum generation[11].

The list of potential dominant power plants is long and will first of all depend on transmission capacity in the analysed regions. In order to compare the RSI across the

[11] An alternative adjustment, where we put total supply in the denominator would show the concentration of flexible non-hydro generation as a share of total supply. This number would be extremely low because close to 95% of total supply is already fixed, such that it is more productive to analyse the concentration for the residual demand and supply as in equation 7.

regions (similar to HHI), I reduce the formulation of RSI to the lowest RSI at time *t* for all firms in the region, i.e. the role of the dominant player[12] in the region at time *t*.

$$RSI_t = \frac{Total\ Supply_t - \max(g_{i,t})}{Total\ Demand_t}, \tag{8}$$

where $i \in I$ and I *is* the set of all firms in the region, $\max(g_{i,t})$ is the maximum generation capacity for all firms in the region at time *t* and *Total Supply* is all available generation capacity in the region plus transmission capacity from other areas to the area of interest at time *t*.

Transmission congestion plays an important role in estimating market power. Transmission capacity is defined by the SO for the capacity market, which reflects the maximum capacity of the grid in the SC-OPF for the peak hour of the year (see Figure 5.1 for more details). The use of actual flows between FFZs would lead to distortions, because flows between FFZs are a result of the ATS clearing and potentially already being manipulated by market participants, which is the main subject of this article.

The adjusted RSI*, i.e. RSI based only on non-hydro generation, can be calculated by changing the set *I* to include only non-hydro generators as follows:

$$RSI_t^* = \frac{Total\ Supply_t - \max(g_{i,t}^*)}{Total\ Demand_t}, \tag{9}$$

where $\max(g^*)$ is the maximum of nuclear and thermal capacity for all firms in the FFZs at time *t*. Similarly, the RSI for flexible non-hydro generation can be formulated as:

$$RSI_t^{**} = \frac{Total\ Supply_t - \max(g_{i,t}^* - g_{i,t}^{*\min})}{Total\ Demand_t}. \tag{10}$$

For simplicity, I denote the indices above using * for the first adjustment by removing hydro power plants from the set of generators that can exert market power, ** by focusing only on the available flexible non-hydro generation and RSI*** is RSI** calculated based only on the supply available in the area, i.e. excluding transmission capacity to other areas.

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[12] The dominant player in the area might change over time. The RSI for the area allows us to compare areas as we would using the HHI.

By removing hydro power plants from the calculation, the HHI drops from 800/1421 to 694/177 (HHI*) and further to 327/52 (HHI**) by removing minimum generation in the calculation of the producers' share (see Table 4.1). Notice that HHI is higher and HHI*/HHI** is lower for the Siberian price zone, where prices traditionally have been 20–40% below prices in the European price zone.

Table 4.1 Average HHI and RSI metrics for the price zones

Price Zone	HHI	HHI*	HHI**	RSI	RSI*	RSI**	RSI***
Europe-1	818	694	327	0.97	0.97	1.18	1.16
Siberia-2	1421	177	52	1.02	1.30	1.37	1.28

**adjusted for hydro, **flexible generation, ***excluding transmission to other FFZs.*

The average values of both RSI* and RSI** are significantly lower for the European zone compared with the Siberian zone. The capacity between the zones is relatively small compared with the available capacity in zone 1, but close to 5–10% in zone 2 depending on the season. Thus, the RSI with or without transmission capacity differs more for the Siberian zone compared with a marginal decrease of 0.02 on average for zone 1.

Table 4.2 Share (%) of hours with RSI*/RSI below 1/1.1/1.2 in price zones**

Price Zone	RSI*<1	RSI*<1.1	RSI*<1.2	RSI**<1	RSI**<1.1	RSI**<1.2
Europe-1	67%	94%	100%	-	16%	65%
Siberia-2	0.1%	1%	19%	0.1%	0.2%	3%

**adjusted for hydro, **flexible generation, ***excluding transmission to other areas, "-" means no observations below the threshold in the analysed period.*

The adjusted RSI** relevant for the DAM and RSI* relevant for the UC auctions were below 1.1 for 16% and 94% of hours in the analysed period in the European zone and do not pass Sheffrin's (2012) rule of thumb that the RSI should not be below 1.1 for more than 5% of hours.

Notice in Figure 4.1 that removing hydro capacity in the calculation of the HHI* leads to a 20% drop compared with the traditional HHI in price zone 1. A similar correction for the Siberian zone in Figure 4.2 demonstrates the dominating role of hydro generation, which is used to maximize social welfare in the objective function of the clearing mechanism. Similarly, HHI** calculated based on the share of flexible non-hydro generation leads to further decreases in the concentration index.

First adjustment of RSI to RSI* (ignoring hydro generators) leads to only small effects in price zone 1, but results in a 15–20% increase in zone 2. Hydro producers have a considerably larger share of the available capacity in zone 2 and thus more market power in traditional metrics.

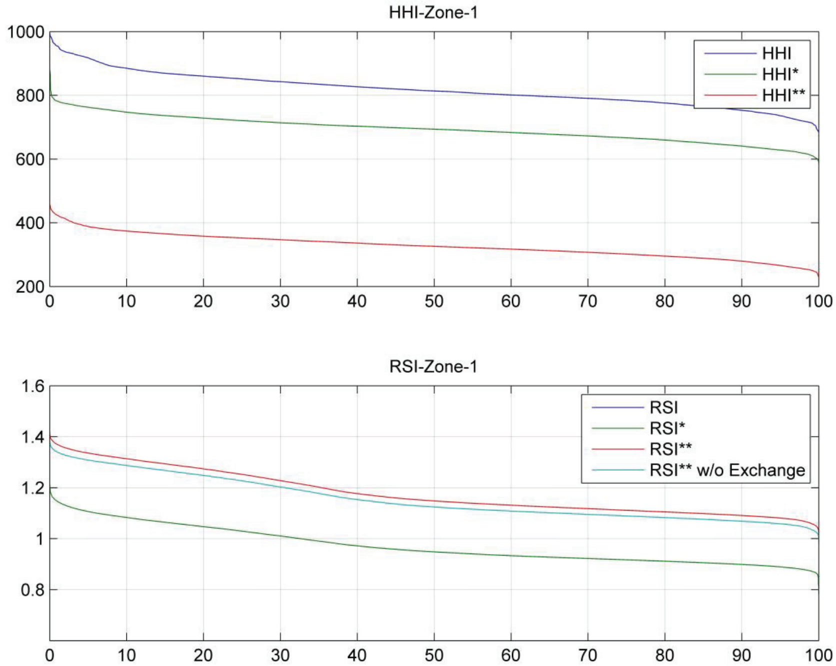

Figure 4.1 Duration curves for the HHI and RSI in European price zone

For the UESs in Table 4.3, the situation is similar in that HHI* is significantly below the traditional HHI in the zones with a significant share of hydro generation, for example, South and Volga. The adjustment for capacity below minimum generation shows a further drop in HHI** to around 18% of traditional HHI for UES2 Volga, UES3 South and UES4 Northwest. Nuclear generation is dominant in Northwest, but is not flexible. The HHI is 30% above HHI**, but almost identical to HHI* for UES5 Center. The second adjustment, i.e. removing fixed and hydro generation, illustrates that the concentration in UES Ural-1 is higher when calculated for the residual demand compared with the traditional HHI.

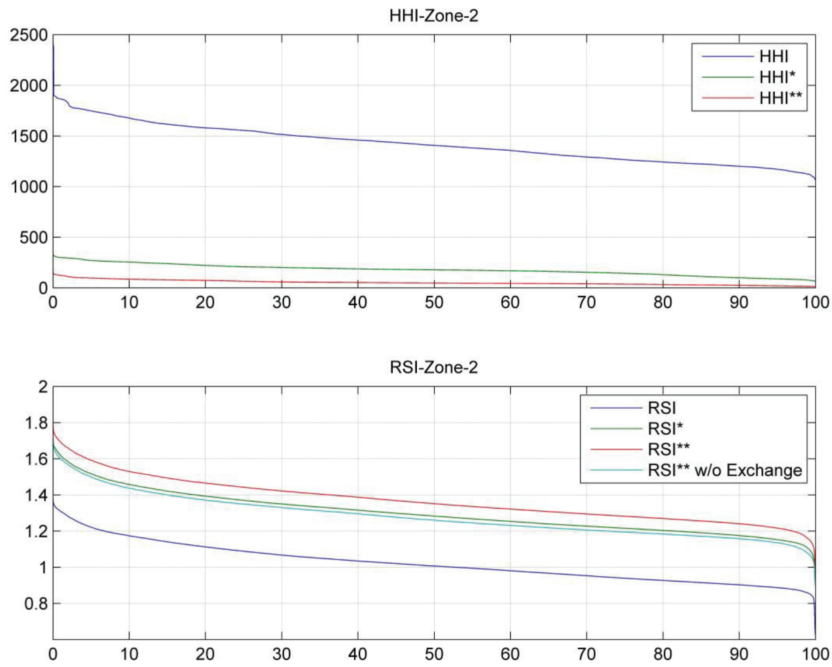

Figure 4.2 Duration curves for the HHI and RSI in the Siberian price zone

The role of available transmission capacity can be seen in Table 4.3, because the RSI*** index based only on the supply available in the UESs drops by 0.09–1.5 depending on the area. The adjusted RSI** is well above the RSI* for all regions, whereas the RSI* is below the critical threshold of 1.1 for 0.6% of the time in UES Ural and 21% in UES Northwest (see Table 4.4 for more details). RosEnergoAtom, the nuclear generator in UES Northwest-4 with 40% of installed capacity is pivotal and dominant in the UC auctions and capacity market.

Table 4.3 Average HHI and RSI metrics for the UESs

UES	HHI	HHI*	HHI**	RSI	RSI*	RSI**	RSI***
Ural-1	905	877	1016	1.22	1.22	1.33	1.05
Volga-2	1785	1124	328	2.50	2.52	2.78	1.24
South-3	2028	902	363	1.78	1.93	2.12	1.21
NWest-4	3217	1909	605	1.17	1.25	1.66	1.29
Center-5	1978	1959	1364	1.56	1.56	1.89	1.13

**adjusted for hydro, **flexible generation, ***excluding transmission to other areas*
UES Siberia corresponds to Price Zone 2 in Table 4.1.

The high share of flexible thermal generation (only 4% is flexible hydro) explains the situation in Ural[13], whereas by looking at FFZ7 Ural, FFZ8 Tyumen and FFZ9 North Tyumen (see Table 2 in Appendix 1) it is clear that only FFZ8 suffers from high concentration where the RSI* is below the critical value for 52% of hours in the analysed period. The dominant position of Lukoil in FFZ18 Kaspiy is also confirmed by the RSI* being below 1.1 for 65% of all hours during the analysed period, while the RSI** is above 1.2 for the entire period. FFZ26 Moscow in UES Center suffers from poor competition with RSI*/RSI** below 1.1 for 98%/47% of the time.

Table 4.4 Share (%) of hours with RSI below 1/1.1/1.2 in UESs

UES	RSI*<1	RSI*<1.1	RSI*<1.2	RSI**<1	RSI**<1.1	RSI**<1.2
Ural-1	-	0.6%	46%	-	-	0.4%
Volga-2	-	-	-	-	-	-
South-3	-	-	-	-	-	-
NWest-4	4%	21%	44%	-	-	-
Center-5	-	-	-	-	-	-

**adjusted for hydro, **flexible generation, ***excluding transmission to other FFZs; "-" stands for no observations below the threshold in the analysed period. UES Siberia corresponds to Price Zone 2 in Table 4.2.*

Table 2 in Appendix 1 illustrates the role of transmission capacity in the calculation of the RSI for the FFZs. The average difference between the RSI** with/without available supply from other regions (RSI***) is 1.27, with values ranging from 0.17 (a decrease from 1.59 to 1.42 in FFZ1 Siberia) to 4.16 (a decrease from 5.56 to 1.4 in FFZ17 Volgograd). For FFZ2 Kuzbass, FFZ3 Omsk, FFZ6 Altay, FFZ9 North Tyumen, FFZ12 Vyatka, FFZ18 Kaspiy and FFZ26 Moscow, the RSI*** is below 0.7 on average for the analysed period, which implies that more than 30% of demand depends on pivotal producers if there is no transmission capacity to other areas. For more details on the role of adjustment in the RSI for the FFZs, see Table 2 in Appendix 1.

5 TRANSMISSION-CONSTRAINED RSI

Gore et al. (2011) and Chernenko (2015) state that the heavily congested electricity transmission network in Russia leads to deviations from the market-based merit order

[13] UES Ural consists of FFZ7 Ural, FFZ8 Tyumen and FFZ9 North Tyumen.

of generation and the appearance of isolated markets with high generation concentration. Most of the producers have generation capacity in the different FFZs, which can lead cross-zonal optimization to force congestions (Mirza and Bergland 2012). Indeed, transmission congestion is crucial in the analysis of market power (Hogan 1997), but the formulation of the market does not allow for ex post analysis in a formal way, as demand for reactive power, topology description and transmission capacity of the grid can be calculated only by using the same algorithm and the same dataset as the ATS.

Nevertheless, by ignoring Kirchhoff's laws and accepting that the FFZs calculated by the SO are defined correctly, one can apply a zonal clearing model with transmission constraints on active power flows between the zones to calculate the TCRSI.

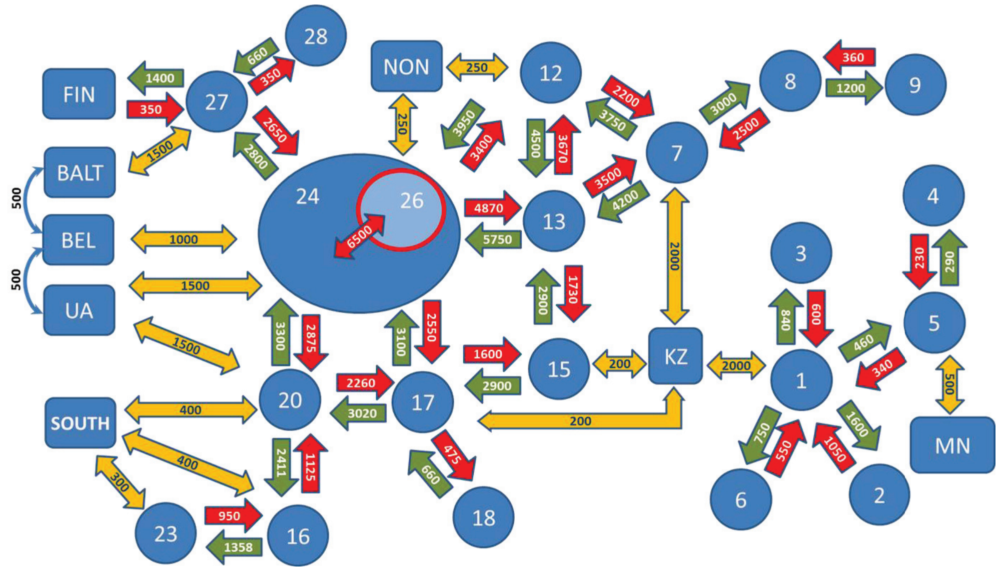

Figure 5.1 Description of the transmission capacities between the FFZs as of 2015

Blue circles illustrate the FFZs. The last number in the code for the FFZs is in the circle, FIN – Finland, BALT – Baltic countries, BEL – Belorussia, UA – Ukraine, SOUTH – Armenia, Georgia, MN – Mongolia, KZ – Kazakhstan and NON – non-market zones. Inner arrows and numbers represent transmission capacity as calculated by the SO for 2015. I assume relatively large capacities to neighbouring countries in order to avoid unnecessary congestion. Since 2012, the transmission capacities have increased between UES Center and UES South/UES Volga. A full list of maximum transmission capacities between the FFZs as calculated by the SO for 2012 to 2015 is available on request from the author. Yellow arrows illustrate links to other countries.

Every year since the launch of the capacity market, the SO has published peak transmission capacity between the zones in both directions because of loop flow. I assume that the FFZs are as defined in 2015[14] and that transmission capacity is a constant value throughout the 8760 hours of the year (see Figure 5.1 for more details). A full list of peak transmission capacities between the FFZs as calculated by the SO for 2012 to 2015 is available on request from the author.

The objective function for the linear problem in calculating the TCRSI* is to find what share of demand above actual consumption[15] can be covered when the non-hydro capacity (flexible capacity for the TCRSI**) of one dominating generator (market participant) is removed from the market. Demand by the FFZs, generation per generation unit (as defined by the ATS), consumption per FFZ and flows between the zones are variables in the model. By setting generation constraints to available total or flexible non-hydro generation[16], I can model the TCRSI* and TCRSI**, respectively. The hydro generation is fixed to actual generation. For the FFZs, where the capacity (flexible capacity) of the dominant generator is removed, I set the minimum/maximum constraint for the consumption variable at 50%/200% of actual consumption, because we are only interested in whether consumption above 110% of actual consumption can be covered while removing the capacity/flexible capacity of the dominant market participant. The remaining consumption variables are fixed to the actual consumption level in the FFZs. See Model 2 in Appendix 2 for more details on mathematical formulation.

I reduced the number of market participants of interest from 192 as registered at the ATS during the analysed period to 35 firms with thermal or nuclear generation based on their shares of maximum and available capacity in Russia. The largest market participant is RosEnergoAtom with 14% of maximum available capacity and 1% of flexible capacity. The second largest is OGK-2 with 8%/6% of flexible and maximum available capacity, respectively, which gives a significant advantage in the DAM

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[14] Some smaller FFZs became part of larger FFZs, which implies that we can still use the transmission capacity of larger zones in the zonal market formulation.

[15] For practical reasons I set a maximum constraint on demand equal to three time the actual consumption in the zone.

[16] I assume that only non-hydro capacity can be used to manipulate prices, whereas other restrictions apply to hydro generation.

compared with RosEnergoAtom. The smallest participant in the analysis accounts for only 0.2%/0.1% of total capacity in Russia. See Table 4 in Appendix 1 for more details.

Overall, there are approximately 22 000 hours where the model found a solution in the base case (without constraints on the capacity of any firm), i.e. the complete dataset excludes periods with missing values for any inputs in the model. Thus, I run the model for 35×22 000 hours to find the TCRSI*/TCRSI**, i.e. removing available capacity/available flexible capacity for the 35 firms of interest. In order to avoid unnecessary bounds for the linear problem in finding the TCRSI, and to reduce the complexity and time to solve the problem, I assume relatively large capacities to the neighbouring countries.

The analysis of the TCRSI**, which is relevant for the DAM, reveals that there are issues with the dominant position of at least one market participant in 10 of the 21 FFZs. The TCRSI** is below 1.1 for at least 5% of hours for all FFZs in the Siberian price zone except for FFZ2 Kuzbass. The TCRSI** is below 1.1 for 10% and 42% of all hours in FFZ7 Ural and FFZ8 Tyumen, respectively. The value of the TCRSI** is below the threshold for 19% and 55% hours in the analysed period in FFZ24 Center and FFZ26 Moscow in UES Center. In Northwest UES, the TCRSI** is below the threshold for 9% of the time in FFZ27 West. The analysis shows that the assumption on available transmission capacity to neighbouring zones in the calculation of the RSI is too optimistic. For comparison, the RSI** was critically low in only four FFZs; see Table 10.3 in the Appendix 1 for more details.

The analysis of the TCRSI* based on the available capacity shows that there exists at least one pivotal market participant for more than 95% of hours in 14 of the 21 FFZs. In addition to the previously named FFZs in the discussion of the TCRSI**, the TCRSI* exceeds the critical threshold in FFZ2 Kuzbass, FFZ18 Kaspiy, FFZ20 Kuban and FFZ28 Kolskaya. The existence of hydro power plants in the FFZs and sufficient transmission capacity also reduce the potential to exert market power in the markets, where total available capacity can be used to maximize profits, as in the UC auctions and capacity market.

6 The Relationship between Price and TCRSI

The basic approach to analysing whether prices exceed marginal costs has traditionally been the calculation of the LI, given by (Price – MC)/Price and is based on the estimate of the weighted average marginal cost (MC) of the pivotal/marginal generator at time t.

The sturdiest critique against this method is that one also needs to take into account long-run marginal cost (LRMC) in the discussion of the LI and consequently the market power level (Newbery 2008; Brennan 2002). For the Russian power market one can ignore LRMC because fixed costs (such as maintenance expenses, capital costs, etc.) are recovered in the capacity market. Start-up costs can also be ignored because these are calculated based on the solution of the UC auctions and not in the DAM in Russia.

The scarcity prices, which are far in excess of the cost of the last unit, also arise under perfect competition and with free market entry (Ockenfels 2007). Opportunity costs similar to the water value for hydro producers in the Nord Pool and the uncertainty that producers face in the DAM is difficult to take into account and one ends up estimating average marginal costs for the different types of technology in the market. The objective function of the market-clearing algorithm for the Russia power market is to maximize social welfare satisfying all constraints during a 24-hour period. The nodal prices or locational marginal prices (LMPs) are the marginal prices, i.e. price sensitivities that are produced at the solution of the optimization problem. Price smoothing in the ATS clearing mechanism ensures that only generator offers can clear the market and that nodal prices are non-negative[17]. LMPs differ between locations because of transmission congestion and losses. Nodal prices consist of the marginal cost of meeting total demand at the reference bus j (price of energy), marginal cost of transmission losses (thermal losses in the transmission lines from the reference bus j to bus i) and marginal cost of transmission congestion (from bus i to the reference bus j) because of binding constraints, e.g. binding transmission line constraints (Litvinov et al. 2004).

[17] A non-negativity condition is common for the DAM, UC three-day-ahead auctions and the capacity market.

The properties of the nodal prices lead to some non-obvious effects, where seemingly irrelevant constraints may change the equilibrium solution (Björndal, Gribkovskaia, and Jörnsten 2014). The LMP at a bus does not have to be equal to the offer of any single generator, because the LMP is the marginal cost of increasing load at a particular location. In most cases, the nodal price at most nodes will be determined by the offers of generators from other locations in the transmission system. If the generators are fully dispatched, the nodal price that is paid is determined by the offers of other generators and will be greater or equal to the generator's offer. Only the marginal unit that is partially dispatched will generally set the locational price at its location. Thus, the relationship between the marginal costs of generation is not straight forward in the LMP market even without market power. The average nodal price index for the FFZs is the volume-weighted average of nodal prices in the FFZs and thus will reflect the marginal offer, average loss price (relative to the reference bus) and average congestion costs in the FFZs.

The tariff for natural gas is adjusted quarterly by Federal Tariff Services (FST), whereas coal is bought mainly based on long-term agreements before the heating season in September. Global coal prices have been relatively stable at around US$45–60/tonne for the last three years, whereas transportation costs (up to US$30/tonne) in Russia are regulated annually by the FST. Thus, fuel costs are fixed in the short term and changes in marginal costs for each generator should only change demand or the level of heat generation. Most of the thermal power plants in Russia have a distinct generation profile based on heat demand in the city/region. The price of heat is regulated by the FST, but the creation of a market for heat has been discussed. When heat generation increases, electricity becomes a bi-product and the overall efficiency of a power plant increases, which should be reflected in lower offers from these combined heat and power plants. The heating season is defined for each administrative region separately when the average 5–7-day temperature is below 12–16°C.

Based on these assumptions, the marginal costs of generators should not change when heat and electricity demand is constant and fuel prices are given. The increase in price should be based on an increase in demand, a decrease in fixed generation and available capacity because of outages or congestion. For simplicity, I assume that the average marginal costs in Russia are given by 50% efficiency natural gas power plant, and any deviations in price are caused by an increase in actual generation above the minimum[18].

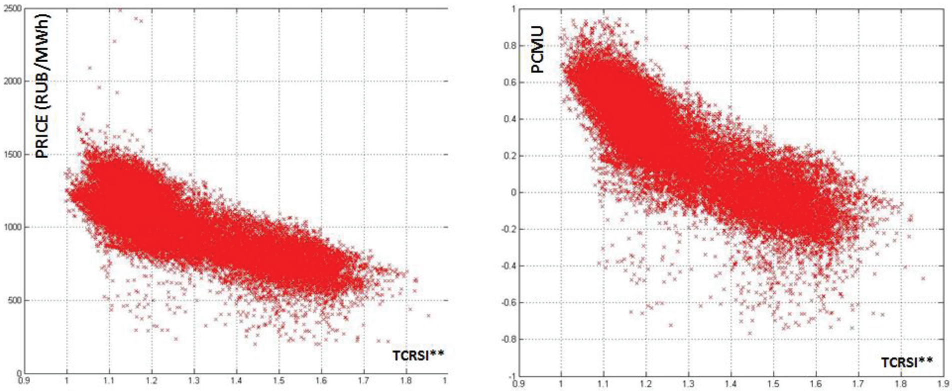

Figure 6.1 TCRSI and price (left) and PCMU (right) for OGK-2 in FFZ27**

Due to the number of zero prices (reflection of congestion), I limit further discussion to the analysis of the relationship between the TCRSI and price–cost mark-up (PCMU). The close relationship between LI and PCMU is shown in Newberry (2008) and represented by a linear function:

$$PCMU = \frac{p - mc}{mc} = \frac{LI}{1 - LI}. \tag{11}$$

By running a simple ordinary least squares (OLS) regression on price in the FFZs, we can test for correlation between PCMU/price and the TCRSI for potential pivotal generators in each zone. The latter is defined by the share of the TCRSI** below the threshold for at least 5% of hours in the analysed period. Overall there are 13 generators in the 10 FFZs that do not pass the rule of thumb in the DAM (i.e. TCRSI**) for which I estimate following relationship:

$$PCMU_t = \alpha_0 + \alpha_1 t + \beta_{TCRSI} TCRSI_t + \beta_{Flex} Flex_t + \beta_{TCRSI*Flex} (TCRSI_t - \overline{TCRSI}) * (Flex_t - \overline{Flex}) + \ldots$$

$$\ldots + \beta_{LD} LD_t + \sum_{i}^{24} \beta_i^{Hour} * D_{t,i}^{Hour} + \beta_{WD} WD_t + \beta_{Temp} Temp_t + \beta_{Hydro} Hydro_t + \varepsilon_t, \tag{12}$$

[18] That is, I use a linear function of flexible non-hydro generation represented mainly by natural gas power plants. Fuel costs = gas price / calorific value / efficiency, where calorific value = 6.97 MWh/1000 m^3. Gas power plants clear the market in Russia primarily during peak hours.

where *Flex* is the share of actual non-hydro generation above the minimum of total flexible generation (see Figure 6.2), *LD* is day length, *D* is a dummy for hour of the day, *Temp* is defined as heating degrees below 16°C in the region and *Hydro* is hydro generation in the FFZs, and ε is the residual term. By substituting *PCMU* by price in the FFZs in equation 12 we can also estimate the relationship between the price and the TCRSI directly.

The augmented Dickey–Fuller test suggests that, for all variables, the null hypothesis of the presence of a unit root is rejected at the 5% level of significance. Autocorrelation in the residuals, detected by using the Breusch–Pagan test, implies that the OLS estimates are still unbiased, but no longer efficient. The results for the regressions for *Price* and *PCMU* based on Newey–West HAC standard errors, which are robust to autocorrelation as well as heteroscedasticity, are reported in Appendix 1 in Tables 5 and 6, respectively.

The *Flex* variable represents the share of total flexible supply above the minimum necessary to cover residual demand, including the pivotal producer assuming price inelastic demand. The rotation variable *TCRSI*Flex* allows us to see how the slope of the supply curve represented by the *Flex* variable changes when the TCRSI changes. Notice that the TCRSI depends on the changes in the capacity of the firm analysed, the share of available capacity of other suppliers in the region, transmission capacity and demand.

PCMU for all market participants is significantly correlated with either day length or heating degrees or both. Price is not correlated with day length or heating degrees for OGK-3 and TGK-14 in FFZ4 and TGK-11 in FFZ3. Coefficients for the hourly dummy and workday dummy are significant for the majority of the market participants in the analysis.

Figure 6.2 demonstrates the effect of the TCRSI and *Flex* variable when β_{TCRSI} and $\beta_{TCRSI*Flex}$ are negative. The more flexible generation is used to cover demand when the price is high, which in turn leads to a higher PCMU. For most market participants it is also true that a decrease in the TCRSI leads to an increase in the slope of flexible supply. To explain the role of the TCRSI it is simpler to look at the results for the estimation of price in equation 12. For OGK-2 in FFZ8, the coefficient for the TCRSI is –1119, 1100 for flexible non-hydro generation and –6962 for the rotation variable (TCRSI*Flex). Assuming 0.1 and 1% change in the TCRSI and generation (*Flex*), respectively, the overall price increase of 138 RUB/MWh is distributed as 120 RUB/MWh because of a vertical shift in the supply curve (effect of –0.1 shift in the TCRSI), 11 RUB/MWh because of a 1% increase in thermal generation (*Flex*) and 7 RUB/MWh because of a positive shift in the supply curve (TCRSI*Flex).

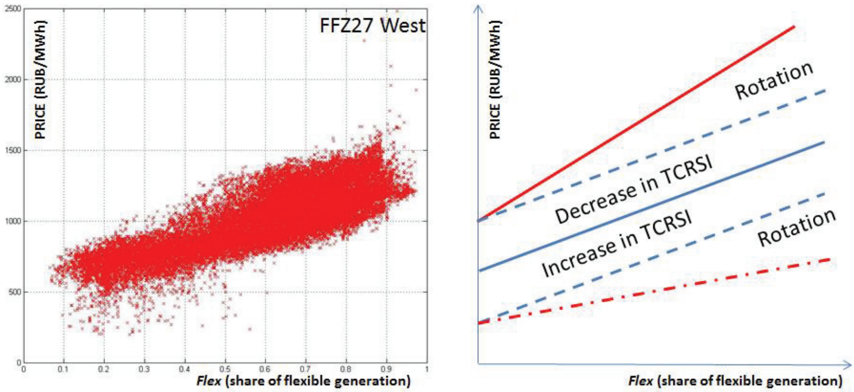

Figure 6.2 Relationship between *Flex* and price in FFZ27 West (right) and illustrating the role of rotation variable *Flex*TCRSI* (left)

The coefficients for the TCRSI and *Flex* are significantly different from zero for all firms in all FFZs in the analysis. For the majority of firms analysed, the coefficient for TCRSI is negative, implying a higher price the more dominant the position of the firm in the FFZs. For OGK-3 in FFZ5 Buryatiya, Kuzbass Energo in FFZ6 Altay, Irkut Energo in FFZ1 Siberia and TGK-11 in FFZ3 Omsk, the coefficient for TCRSI is positive, which implies that the higher is the share of other suppliers in the FFZs, the higher is the price. The only possible explanation is that despite the pivotal position in the FFZs, these market participants are less costly compared with other suppliers in the respective FFZ and seldom set the price in the region.

The regions and firms of special concern, i.e. where the increase in a firm's dominance is reflected in a positive shift in the supply curve, but also in the steepness of the supply curve, are: FFZ4 Chita, FFZ7 Ural, FFZ8 Tyumen, FFZ24 Center and FFZ26 Moscow and market participants: OGK-1, OGK-2, OGK-3, Eon, MosEnergo, Volgograd TGK, Inter RAO, TGK-14 and RosEnergoAtom. See Tables 10.5 and 10.6 for more details on the regression results for price and PCMU, respectively.

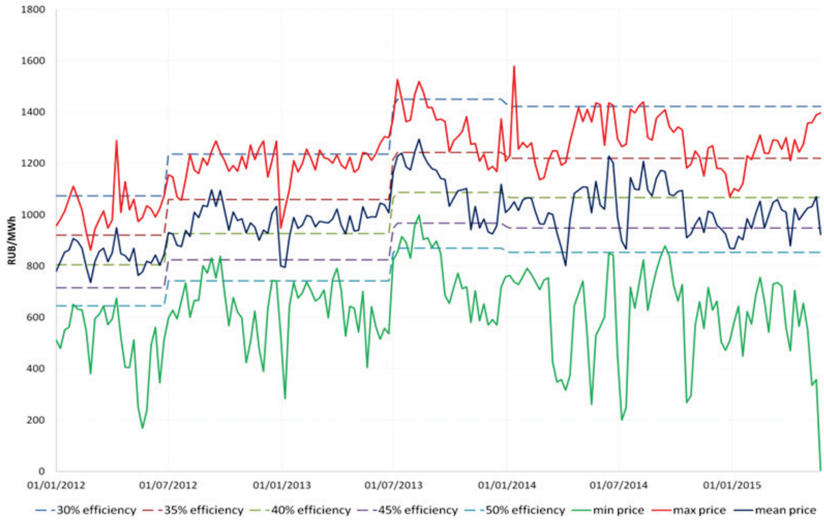

Figure 6.3 Weekly min/mean/max price in FFZ27 West

The maximum/mean/minimum price compared with the fuel costs for natural gas power plants based on a 30–50% efficiency rate in FFZ27 West are illustrated in Figure 6.3. It is clear that the price is close to the marginal costs of a 30% efficiency gas power plant during peak hours and to a 50% efficiency gas power plant during off-peak hours. The average price in FFZ27 corresponds approximately to the fuel costs of a power plant with 35–40% efficiency. According to public information from Gazprom and Inter RAO[19], the efficiency of generation capacity installed recently is in the range of 48–55%, whereas efficiency for older units can be below 30%. Further analysis should focus on the estimation of marginal costs for the unit that clears the market, and the loss and congestion components in the nodal prices.

7 Discussion and conclusion

In this article I describe the functioning of the long- and short-term power markets in Russia including the spot DAM, UC auctions and the capacity market. The main distinction between these markets in terms of market power is in available flexible generation. The analysis of market power in the Russian electricity spot market must

[19] www.gazprom.ru, www.ogk2.ru, www.irao-generation.ru

take into account the fact that the majority of generation is already committed and that hydro generation is regulated by the SO and ATS through the objective function in the clearing mechanism. The adjusted HHIs and RSIs are dramatically below the values previously stated in the existing literature when it comes to price zones and UESs.

Nevertheless, the concentration measured by the adjusted HHI is above 6000 in some FFZs, but also above the traditional HHI, which implies that concentration is even higher when analysing residual demand. The hydro-adjusted RSI*, relevant for UC auctions and the capacity market, is below the 1.1 threshold for more than 5% of hours in the analysed period in nine of 21 FFZs. For the DAM, i.e. RSI** adjusted for hydro and fixed generation, the number of hours when there exists a pivotal generator is above the threshold in only two FFZs, Altay and Moscow. The adjusted RSI** value decreases by 0.7 on average if the transmission capacity to neighbouring zones is removed from the available supply in order to substitute the pivotal generator in the FFZs, which illustrates the role of transmission capacity in market power analysis.

The TCRSI** (adjusted for hydro and fixed generation) reveals that concentration is critical in 10 FFZs, primarily in UES Siberia and UES Center. OGK-2 is pivotal for at least 5% of hours in the analysed period in four FFZs, whereas OGK-3, Eon and Inter RAO EG are pivotal in two FFZs each. Overall, 13 of the 35 market participants were pivotal in at least one FFZ for more than 5% of hours in the analysed period. For UC auctions and the capacity market, the situation is critical for 14 of 21 FFZs and 16 of 35 market participants were pivotal for more than 5% of hours in the analysed period. The TCRSI* is below 1.1. for at least 50% of hours in the analysed period for 12 FFZs, including UES Siberia (except FFZ1 Siberia), UES Ural, UES Center and UES Northwest.

The strong correlation between PCMU/price for the FFZs and TCRSI** might be an indication that pivotal producers are aware of their position and exert market power. Correlation does not imply causation and potentially there are other explanations for this effect. The calculation of the TCRSI based on nodal formulation, inclusion of ramp-up/down and the integral constraint on fuel/water availability and a focus on the generator level in estimating marginal cost could obviously reveal more about this relationship.

The analysis in this article supports the previous findings of high market concentration in the Russian power market, but for different reasons. The adjusted HHI is below 1400 on average for all price zones and the UESs and the adjusted RSI show that there exist pivotal generators for more than 5% of hours in only two FFZs in the analysed period. Nevertheless, the TCRSI reveals that market concentration is critical for the majority of the FFZs in Russia in UC auctions, the DAM and capacity market. Market concentration decreases the higher is the share of hydro producers and transmission capacity to the neighbouring regions in the Russian power market in general and in addition depends on the share of fixed generation in the DAM.

Future research should focus on a detailed decomposition of nodal prices, the role of losses, transmission constraints in optimal power flow problem and estimation of the marginal costs of each market participant at the generator level.

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APPENDIX 1. TABLES

Table 1 FFZ average metrics as a share of maximum generation

Free Flow Zone	Maximum generation (MW)	Average hourly consumption	Non-hydro generation	Hydro generation	Flexible non-hydro generation	Flexible hydro generation
Siberia-1	25 048	69 %	35 %	65 %	9 %	50 %
Kuzbass-2	1 251	135 %	100 %	-	17 %	-
Omsk-3	956	127 %	100 %	-	20 %	-
Chita-4	941	89 %	100 %	-	25 %	-
Buryatiya-5	705	75 %	100 %	-	27 %	-
Altay-6	736	132 %	100 %	-	26 %	-
Ural-7	18 272	91 %	96 %	4 %	30 %	3 %
Tyumen-8	11 323	82 %	100 %	-	33 %	-
NTyumen-9	410	193 %	100 %	-	43 %	-
Vyatka-12	3 461	115 %	60 %	40 %	16 %	39 %
Volga-13	7 103	86 %	69 %	31 %	19 %	28 %
Balakovo-15	5 258	26 %	81 %	19 %	3 %	18 %
Kavkaz-16	1 572	120 %	65 %	35 %	30 %	35 %
Volgograd-17	2 623	69 %	23 %	77 %	5 %	64 %
Kaspiy-18	469	101 %	100 %	-	39 %	-
Kuban-20	6 060	76 %	97 %	3 %	22 %	3 %
Mahachkala-23	1 400	45 %	0 %	100 %	1 %	99 %
Center-24	22 786	74 %	92 %	8 %	16 %	8 %
Moscow-26	9 160	119 %	100 %	-	31 %	-
West-27	7 911	79 %	89 %	11 %	16 %	5 %
Kolskaya-28	2 514	58 %	47 %	53 %	0.4 %	53 %

Non-hydro generation includes nuclear and thermal power plants. Flexible generation corresponds to the capacity above minimum generation. Average hourly consumption refers to load in the FFZ.

Table 2 HHI/RSI by FFZ

FFZ	HHI	HHI*	HHI**	RSI	RSI*	RSI**	RSI***
Siberia-1	1880	143	37	1.12	1.52	1.59	1.42
Kuzbass-2	5482	5482	8565	1.13	1.13	1.52	0.62
Omsk-3	9587	9587	9994	0.73	0.73	1.35	0.63
Chita-4	3156	3156	3625	1.04	1.04	1.35	1.00
Buryatiya-5	7123	7123	6616	1.60	1.60	2.41	1.07
Altay-6	4541	4541	7053	1.11	1.11	1.34	0.60
Ural-7	1283	1246	1770	1.37	1.37	1.51	0.99
Tyumen-8	2532	2532	3106	1.10	1.10	1.39	1.04
NTyumen-9	6414	6414	8234	1.68	1.68	1.89	0.32
Vyatka-12	3531	1859	672	3.12	3.16	3.40	0.76
Volga-13	2337	1386	623	3.35	3.40	3.64	1.06
Balakovo-15	5402	5028	293	3.81	3.81	6.40	3.73
Kavkaz-16	5413	3985	2146	2.18	2.19	2.48	0.61
Volgograd-17	6389	341	51	4.49	5.39	5.56	1.40
Kaspiy-18	9941	9941	10000	1.24	1.24	1.84	0.61
Kuban-20	3225	3213	4095	1.70	1.70	2.09	1.13
Mahachkala-23	9917	0.31	0	1.45	3.82	3.82	2.38
Center-24	2489	2429	851	1.90	1.90	2.46	1.30
Moscow-26	6668	6668	6378	0.69	0.69	1.17	0.64
West-27	2833	2126	1899	1.31	1.36	1.71	1.18
Kolskaya-28	5131	2024	0.22	1.01	1.22	1.99	1.73

*-adjusted for hydro, **- flexible generation, ***-excluding transmission to other FFZ

Table 3 RSI and TCRSI below 1.1 threshold by FFZ

FFZ	RSI* <1	RSI* <1.1	RSI* <1.2	RSI** <1	RSI** <1.1	RSI** <1.2	TCRSI* <1.1	TCRSI** <1.1
Siberia-1	-	-	0.1 %	-	-	0.1 %	41 %	24 %
Kuzbass-2	19 %	42 %	62 %	-	-	-	74 %	1 %
Omsk-3	96 %	99 %	100 %	-	3 %	20 %	100 %	19 %
Chita-4	45 %	69 %	85 %	1 %	2 %	11 %	99 %	31 %
Buryatiya-5	-	4 %	12 %	-	-	-	81 %	5 %
Altay-6	36 %	57 %	73 %	3 %	16 %	36 %	72 %	37 %
Ural-7	-	-	1 %	-	-	0 %	76 %	10 %
Tyumen-8	7 %	52 %	94 %	-	-	1 %	100 %	42 %
NTyumen-9	-	-	-	-	-	-	3 %	-
Vyatka-12	-	-	-	-	-	-	-	-
Volga-13	-	-	-	-	-	-	-	-
Balakovo-15	-	-	-	-	-	-	-	-
Kavkaz-16	-	-	-	-	-	-	1 %	-
Volgograd-17	-	-	-	-	-	-	-	-
Kaspiy-18	20 %	35 %	51 %	-	-	-	38 %	-
Kuban-20	-	-	1 %	-	-	-	70 %	0 %
Mahachkala-23	-	-	-	-	-	-	-	-
Center-24	-	-	-	-	-	-	97 %	19 %
Moscow-26	96 %	98 %	100 %	20 %	47 %	64 %	99 %	55 %
West-27	-	5 %	21 %	-	-	-	91 %	9 %
Kolskaya-28	6 %	25 %	49 %	-	-	-	77 %	1 %

*-adjusted for hydro, **- flexible generation, TCRSI is calculated only for 35 firms defined in table 10.4, "-" stand for no observations below the threshold in the analysed period.

Table 4 Market participants with non-hydro capacity in calculation of TCRSI

Name	% of Total Flexible Capacity	% of Total Available Capacity	Present in FFZ
OGK-2	8.0 %	6.9 %	(1,7,8,2,24,27)
Eon	6.6 %	5.0 %	(1,7,8,24,26)
Enel	5.5 %	4.1 %	(7,16,24)
Mosenergo	5.9 %	5.9 %	(26)
OGK-1	5.4 %	3.7 %	(7,9,24,26)
OGK-3	3.5 %	3.0 %	(1,3,4,5,7,24)
Fortum	2.4 %	2.3 %	(7,8)
BGK	2.7 %	2.0 %	(7)
Volzhskaya TGK	2.0 %	2.3 %	(7,12,13,15,24)
Kuzbassenergo	1.9 %	1.8 %	(1,2,6)
Genko TAT	2.8 %	1.6 %	(12,13)
Nignevartovskaya GRES	1.5 %	1.1 %	(8)
Interrao Electrogeneration	2.4 %	1.8 %	(1,5,7,9,2,24,26,27)
TGK-5	1.7 %	1.3 %	(12)
TGK-1	4.6 %	2.9 %	(27,28)
Irkutskenergo	11.5 %	5.9 %	(1,2,3)
Kvadra	1.3 %	1.2 %	(24)
TGK-9	1.2 %	1.2 %	(7,12)
TKG-6	1.4 %	1.3 %	(13,24)
Sibeko	1.1 %	1.2 %	(1,3,4)
Lukoil Kubanenergo	0.8 %	0.6 %	(2)
TGK-11	0.7 %	1.0 %	(1,2,3,4)
Lukoil Astrahanenergo	0.6 %	0.4 %	(18)
TGK-2	0.6 %	0.5 %	(24,27)
Hakass GenCo	0.5 %	0.6 %	(1,4)
Orenburgskaya GenCo	0.6 %	0.5 %	(7)
Nazarovskaya GRES	0.7 %	0.7 %	(1,4)
Lukoil Volgogradenergo	0.6 %	0.5 %	(17)
TGK-14	0.3 %	0.3 %	(1,4,5)
Avtozavodskaya TEC(CHP)	0.5 %	0.3 %	(24)
RosEnergoAtom	1.1 %	13.9 %	(7,15,16,2,24,27,28)
TGK-16	0.3 %	0.6 %	(12,13)
Sanors	0.5 %	0.2 %	(13)
Novoryazanskaya TEC(CHP)	0.2 %	0.2 %	(24)
Irkutenergosbyt EW	0.2 %	0.1 %	(1,6)

EN-energo/genko, GK-generation company, TEC – thermal CHP, EW – energy wholesale, OGK – Wholesale Power Market Generating Company, TGK – territorial generating company.

Table 5 Regression results price (FFZ) on TCRSI** (owner/FFZ)

Owner	OGK-2				Eon		MosEN	OGK-1
FFZ	**7**	**8**	**24**	**27**	**8**	**26**	**26**	**26**
Constant	1220**	1244**	1823**	1471**	1245**	889**	743**	913**
Trend	0.005**	0.005**	0.005**	0.004**	0.006**	0.009**	0.009**	0.009**
TCRSI	**-422****	**-1119****	**-712****	**-552****	**-1068****	**-182****	**-99****	**-195****
Flex	686**	1100**	523**	590**	896**	462**	489**	458**
TCRSI*Flex	**-821****	**-6962****	**-816****	**-536****	**-6442****	57	222**	88
Length day	-215**	-199**	-158**	-135**	-151**	22	59	30
Hour 1	24**	10**	61**	3	26**	27**	24**	23**
Hour 2	14**	3	31**	2	13**	15**	13**	14**
Hour 3	0	-1	2	-3	5	3	2	3
Hour 4	-5**	-1	-8**	-5**	3	-2	-1	-1
Hour 6	8**	3	22**	5	4	4	3	2
Hour 7	-21**	1	24**	-10	13**	-3	-5	-7
Hour 8	-37**	17**	23**	-29**	50**	22**	24**	15
Hour 9	-22**	31**	37**	-19	88**	51**	61**	43**
Hour 10	-12	33**	42**	-6	105**	83**	98**	75**
Hour 11	-15	28**	47**	0	103**	100**	118**	92**
Hour 12	-16	29**	46**	3	103**	98**	114**	90**
Hour 13	-19	25**	42**	1	97**	87**	101**	78**
Hour 14	-18	25**	44**	6	96**	94**	109**	86**
Hour 15	-15	30**	49**	13	99**	98**	113**	90**
Hour 16	-16	30**	48**	8	97**	90**	104**	82**
Hour 17	-20**	28**	49**	-1	95**	78**	91**	69**
Hour 18	-23**	25**	49**	-5	94**	74**	88**	65**
Hour 19	-26**	21**	48**	-1	94**	78**	94**	70**
Hour 20	-34**	6	45**	-3	82**	81**	98**	73**
Hour 21	-37**	-6	43**	-1	67**	84**	100**	76**
Hour 22	-34**	-14**	59**	16	54**	88**	103**	81**
Hour 23	-13**	-8	73**	5	44**	59**	66**	52**
Hour 24	-1	-1	69**	-7	28**	33**	33**	27**
Workday	5	1	2	15**	13**	35**	38**	35**
Temp	-4.4**	-4.8**	-3.9**	-5.5**	-5**	-6.7**	-6.4**	-6.7**
Hydro	-0.1**	-	-0.1**	-0.3**	-	-	-	-
R2	0.78	0.69	0.82	0.77	0.68	0.81	0.81	0.81
DW	0.23	0.19	0.28	0.29	0.21	0.25	0.26	0.25
% RSI obs. Below 1.1	10 %	20 %	19 %	9 %	42 %	51 %	52 %	44 %

"-" stand for no hydro generation in the FFZ

Table 5 Regression results price (FFZ) on TCRSI (owner/FFZ) (Continued)**

Owner	OGK-3		VolzhTGK	KuzbassEN	InterraoEG	
FFZ	**4**	**5**	**24**	**6**	**24**	**26**
Constant	775**	559**	1544**	490**	1734**	1008**
Trend	0.004**	0.004**	0.004**	0.006**	0.004**	0.009**
TCRSI	**-262****	66**	**-505****	38**	**-670****	**-274****
Flex	263**	237**	597**	275**	602**	450**
TCRSI*Flex	**-372****	56	**-763****	20	**-897****	53
Length day	-28	-141**	-166**	143**	-175**	11
Hour 1	4	-50**	88**	-49**	81**	31**
Hour 2	-1	-41**	49**	-61**	45**	20**
Hour 3	-5	-28**	13**	-66**	11**	7**
Hour 4	-2	-13**	-4**	-45**	-5**	0
Hour 6	1	8**	26**	34**	24**	2
Hour 7	2	12**	36**	58**	29**	-8
Hour 8	6**	9**	49**	73**	36**	14
Hour 9	7**	7**	71**	81**	56**	41**
Hour 10	10**	4	80**	78**	70**	71**
Hour 11	10**	2	87**	79**	80**	88**
Hour 12	11**	2	86**	83**	80**	86**
Hour 13	14**	6**	82**	80**	75**	75**
Hour 14	21**	14**	86**	77**	79**	82**
Hour 15	23**	16**	91**	74**	84**	88**
Hour 16	20**	17**	90**	77**	82**	80**
Hour 17	14**	16**	89**	78**	81**	67**
Hour 18	8**	7**	88**	77**	80**	63**
Hour 19	9**	-12**	85**	83**	79**	66**
Hour 20	10	-28**	79**	79**	77**	69**
Hour 21	13**	-37**	77**	57**	77**	72**
Hour 22	13**	-42**	92**	21**	94**	78**
Hour 23	13**	-47**	106**	-8	103**	53**
Hour 24	8	-53**	101**	-41**	94**	33**
Workday	2	-2	7	25**	9	33**
Temp	0.1	0.8	-4.3**	1.8**	-4.3**	-6.8**
Hydro	-	-	-0.2**	-	-0.2**	-
R2	0.52	0.6	0.81	0.6	0.81	0.81
DW	0.25	0.17	0.28	0.33	0.28	0.25
% RSI obs. Below 1.1	31 %	5 %	7 %	37 %	6 %	55 %

"-" stand for no hydro generation in the FFZ

Table 5 Regression results price (FFZ) on TCRSI (owner/FFZ) (Continued)**

Owner	IrkutEN	TGK-11	TGK-14	RosEnergo Atom	IrkutEWC
FFZ	**1**	**3**	**4**	**24**	**6**
Constant	73	631**	962**	1478**	442**
Trend	0.009**	0.006**	0.003**	0.004**	0.006**
TCRSI	**533****	-7	**-405****	**-478****	69**
Flex	779**	342**	242**	607**	272**
TCRSI*Flex	1029**	-29	**-663****	**-800****	-47
Length day	34	-36	18	-155**	139**
Hour 1	-107**	-4	19**	89**	-62**
Hour 2	-108**	-16**	12**	49**	-74**
Hour 3	-93**	-26**	4	12**	-78**
Hour 4	-53**	-21**	0	-5**	-51**
Hour 6	49**	12**	3	27**	38**
Hour 7	80**	35**	3	38**	64**
Hour 8	92**	57**	6**	53**	79**
Hour 9	95**	66**	7**	77**	88**
Hour 10	93**	65**	10**	88**	83**
Hour 11	93**	66**	10**	96**	85**
Hour 12	93**	70**	11**	96**	88**
Hour 13	92**	65**	10**	93**	85**
Hour 14	99**	64**	13**	96**	82**
Hour 15	104**	61**	10**	103**	79**
Hour 16	112**	63**	5	102**	83**
Hour 17	119**	60**	1	99**	84**
Hour 18	118**	55**	5**	97**	83**
Hour 19	101**	54**	15**	95**	89**
Hour 20	62**	53**	22**	89**	85**
Hour 21	6	44**	25**	87**	57**
Hour 22	-44**	32**	25**	104**	15**
Hour 23	-78**	23**	26**	114**	-18**
Hour 24	-106**	5	23**	104**	-54**
Workday	11	17**	0	7	26**
Temp	4**	-0.4	0.2	-3.7**	1.8**
Hydro	-0.1**	-	-	-0.2**	-
R2	0.57	0.68	0.59	0.81	0.6
DW	0.11	0.37	0.32	0.28	0.34
% RSI obs. Below 1.1	24 %	19 %	14 %	9 %	12 %

“-“ stand for no hydro generation in the FFZ

Table 6 Regression results PCMU (FFZ) on TCRSI (owner/FFZ)**

Owner	OGK-2				Eon		MosEN	OGK-1
FFZ	7	8	24	27	8	26	26	26
Constant	0.25**	0.62**	1.2**	0.96**	0.69**	0.32**	0.04	0.39**
Trend*1000	-0.6**	-0.5**	-0.7**	-0.7**	-0.3**	-0.2**	-0.1**	-0.1**
TCRSI	-0.33**	-1.38**	-0.81**	-0.75**	-1.39**	-0.34**	-0.19**	-0.39**
Flex	0.92**	1.3**	0.57**	0.67**	1.07**	0.49**	0.54**	0.48**
TCRSI*Flex	-1.14**	-7.91**	-0.56**	-1**	-7.54**	0.02	0.19**	0.01
Length day	-1.2	-3.7	8.3**	10**	1.9	28.3**	35.1**	29.7**
Hour 1	2.4**	1.2**	6.8**	3.3**	3.5**	3.2**	3.8**	2.9**
Hour 2	0.9**	0.6	3.3**	2**	1.9**	1.7**	2.1**	1.7**
Hour 3	-0.8**	0.2	0.1	0.2	0.9**	0.1	0.3	0.2
Hour 4	-1.2**	0.1	-1**	-0.7**	0.6**	-0.4	-0.2	-0.3
Hour 6	1.6**	0.4	2.3**	1.2**	0.5	0.6	0.6**	0.4
Hour 7	-1.8**	0.3	1.9**	0.4	1.5**	-0.3	0.2	-0.8
Hour 8	-3.7**	2.5**	2.4**	-0.5	6.2**	2.8**	4.4**	1.9**
Hour 9	-1.7	4.5**	5.4**	1.3	10.9**	6.5**	9.5**	5.2**
Hour 10	-0.3	4.8**	7.7**	2.9	13**	10.4**	14.2**	8.8**
Hour 11	-0.6	4.1**	8.8**	3.7**	12.8**	12.5**	16.7**	10.8**
Hour 12	-0.8	4.2**	8.6**	4.2**	12.7**	12.3**	16.3**	10.5**
Hour 13	-1.3	3.7**	7.8**	4**	12.1**	10.9**	14.6**	9.2**
Hour 14	-1.1	3.7**	8.3**	4.6**	11.8**	11.8**	15.6**	10.1**
Hour 15	-0.8	4.3**	8.9**	5.5**	12.3**	12.5**	16.2**	10.8**
Hour 16	-1	4.3**	8.5**	5**	12**	11.5**	15**	9.8**
Hour 17	-1.5	4**	8.1**	3.9**	11.8**	9.9**	13.4**	8.2**
Hour 18	-1.9	3.7**	7.8**	3.3**	11.6**	9.2**	12.8**	7.5**
Hour 19	-2.3**	3.1**	7.8**	3.7**	11.5**	9.5**	13.4**	7.9**
Hour 20	-3.1**	1.2	7.6**	3.4**	10**	9.8**	13.9**	8.1**
Hour 21	-3.6**	-0.3	7.5**	3.7**	8.2**	10.1**	14.2**	8.5**
Hour 22	-3.2**	-1.6**	9.5**	5.9**	6.5**	11**	14.7**	9.5**
Hour 23	-0.9	-1	9.9**	4.7**	5.6**	7.5**	10.1**	6.3**
Hour 24	-0.1	-0.1	8.1**	3.3**	3.8**	4.1**	5.5**	3.3**
Workday	0.6	0.2	1.4**	1.6**	1.7**	3.9**	4.3**	3.7**
Temp	-0.24**	-0.37**	-0.15**	-0.24**	-0.41**	-0.43**	-0.37**	-0.44**
Hydro	-0.01**	-	-0.02**	-0.06**	-	-	-	-
R2	0.84	0.7	0.87	0.82	0.71	0.86	0.86	0.87
DW	0.35	0.21	0.4	0.38	0.24	0.36	0.37	0.36
% RSI obs. Below 1.1	10 %	20 %	19 %	9 %	42 %	51 %	52 %	44 %

"-" stand for no hydro generation in the FFZ. All coefficients but TCRSI, TCRSI*Flex, Flex are multiplied by 100, whereas coefficient for trend is multiplied by 100 000.

Table 6 Regression results PCMU (FFZ) on TCRSI (owner/FFZ) (Continued)**

Owner	OGK-3		VolzhTGK	KuzbassEN	InterraoEG	
FFZ	4	5	24	6	24	26
Constant	-0.11**	-0.38**	0.97**	-0.5**	1.28**	0.5**
Trend*1000	-0.4**	-0.4**	-0.7**	-0.3**	-0.7**	-0.1**
TCRSI	-0.34**	0.1**	-0.62**	0.18**	-0.88**	-0.48**
Flex	0.34**	0.34**	0.63**	0.35**	0.63**	0.48**
TCRSI*Flex	-0.5**	0.1**	-0.53**	0.04	-0.67**	0
Length day	28**	12.6	7**	34.1**	5.3	26.5**
Hour 1	1	-5.8**	9.9**	-9.8**	9.2**	4.1**
Hour 2	0.2	-4.8**	5.7**	-11.3**	5.1**	2.7**
Hour 3	-0.4	-3.2**	1.6**	-11.2**	1.3**	0.8**
Hour 4	-0.2	-1.4**	-0.3	-7.1**	-0.4	0
Hour 6	0.1	0.9**	2.4**	5**	2.3**	0.2
Hour 7	0.1	1.2**	3.1**	8.5**	2.3**	-1
Hour 8	0.8**	0.9**	5**	10.4**	3.5**	1.8
Hour 9	1**	0.6**	8.8**	11.2**	7.1**	5.3**
Hour 10	1.3**	0.2	11.3**	10.6**	9.9**	8.9**
Hour 11	1.2**	0.1	12.6**	10.6**	11.6**	10.9**
Hour 12	1.4**	0.1	12.4**	10.9**	11.5**	10.7**
Hour 13	1.6**	0.6	11.7**	10.4**	10.7**	9.4**
Hour 14	2.3**	1.4**	12.3**	10.1**	11.3**	10.4**
Hour 15	2.5**	1.6**	12.9**	9.8**	11.9**	11.1**
Hour 16	2.2**	1.6**	12.5**	10.4**	11.4**	10.1**
Hour 17	1.5**	1.5**	12**	10.7**	10.9**	8.5**
Hour 18	0.9**	0.5	11.6**	10.6**	10.6**	7.7**
Hour 19	1.3**	-1.6**	11.5**	11.2**	10.6**	8**
Hour 20	1.7**	-3.3**	10.9**	10**	10.4**	8.2**
Hour 21	2.1**	-4.3**	10.7**	5.9**	10.6**	8.6**
Hour 22	2.1**	-4.9**	12.7**	0.2	12.8**	9.7**
Hour 23	2.1**	-5.4**	13.3**	-4**	13**	7**
Hour 24	1.6	-6.1**	11.7**	-8.5**	11**	4.5**
Workday	0.4	-0.2	1.9**	3.8**	2**	3.7**
Temp	0.28**	0.33**	-0.21**	0.44**	-0.23**	-0.45**
Hydro	-	-	-0.02**	-	-0.02**	-
R2	0.48	0.55	0.86	0.44	0.87	0.87
DW	0.19	0.17	0.4	0.27	0.41	0.36
% RSI obs. Below 1.1	31 %	5 %	7 %	37 %	6 %	55 %

"-" stand for no hydro generation in the FFZ. All coefficients but TCRSI, TCRSI*Flex, Flex are multiplied by 100, whereas coefficient for trend is multiplied by 100 000.

Table 6 Regression results PCMU (FFZ) on TCRSI (owner/FFZ) (Continued)**

Owner	IrkutEN	TGK-11	TGK-14	RosEnergo Atom	IrkutEWC
FFZ	1	3	4	24	6
Constant	-1.03**	-0.28**	0.2**	1.08**	-0.57**
Trend*1000	0.1	-0.3**	-0.5**	-0.7**	-0.3**
TCRSI	0.8**	0.07**	-0.58**	-0.71**	0.21**
Flex	1.01**	0.47**	0.31**	0.61**	0.35**
TCRSI*Flex	1.3**	-0.05	-0.88**	-0.61**	-0.11**
Length day	35.1**	15.4**	34.9**	6.7**	34.5**
Hour 1	-16.5**	-1.5**	3.9**	9.2**	-11.5**
Hour 2	-16.3**	-2.9**	2.5**	5.2**	-13**
Hour 3	-13.9**	-4**	1.2**	1.4**	-12.9**
Hour 4	-7.9**	-3**	0.3	-0.3	-8.1**
Hour 6	7.1**	1.8**	0.2	2.2**	5.8**
Hour 7	11.4**	4.7**	0.1	2.3**	9.5**
Hour 8	12.8**	7.2**	0.7**	4**	11.4**
Hour 9	13.1**	8**	1.1**	7.6**	12.2**
Hour 10	12.7**	7.7**	1.5**	10.1**	11.5**
Hour 11	12.6**	7.7**	1.5**	11.5**	11.6**
Hour 12	12.6**	8.3**	1.6**	11.3**	11.9**
Hour 13	12.5**	7.5**	1.2**	10.6**	11.5**
Hour 14	13.6**	7.3**	1.3**	11.2**	11.1**
Hour 15	14.5**	7.1**	0.6	11.9**	10.8**
Hour 16	15.7**	7.4**	0	11.5**	11.5**
Hour 17	16.8**	7**	-0.3	11**	11.7**
Hour 18	16.5**	6.4**	0.6**	10.6**	11.7**
Hour 19	14**	6.1**	2.5**	10.4**	12.4**
Hour 20	7.9**	5.6**	3.9**	9.8**	11.2**
Hour 21	-0.4	4.2**	4.6**	9.7**	6.3**
Hour 22	-7.7**	2.8**	4.6**	11.8**	-0.3
Hour 23	-12.5**	1.8**	4.8**	12.4**	-5.4**
Hour 24	-16.2**	-0.2	4.5**	10.8**	-10.2**
Workday	1.9**	2.2**	0.1	1.8**	3.7**
Temp	0.76**	0.16**	0.29**	-0.18**	0.45**
Hydro	-0.02**	-	-	-0.02**	-
R2	0.53	0.54	0.56	0.87	0.45
DW	0.1	0.32	0.24	0.39	0.28
% RSI obs. Below 1.1	24 %	19 %	14 %	9 %	12 %

"-" stand for no hydro generation in the FFZ. All coefficients but TCRSI, TCRSI*Flex, Flex are multiplied by 100, whereas coefficient for trend is multiplied by 100 000.

APPENDIX 2. MODELS AND INPUT DATA

Model 1. Short description of market clearing mechanism in Russia

Objective function:

$$\left\{\sum_{c}\sum_{m} c_{ct}^{m} P_{ct}^{m} - \sum_{g}\sum_{m} c_{gt}^{m} P_{gt}^{m}\right\} \to \max$$

Balancing constraint:

$$\sum_{i} p_{ij}^{t} + \sum_{g\,i} P_{gt} - \sum_{c\,i} P_{ct} = 0, \forall\, i - nodes$$

Active power flow:

$$p_{ij}^{t} = G_{ij}[V_i^2 - (V_j V_i \;/ t_{ij})\cos(d_i^t - d_j^t + \alpha_{ij})] + \Omega_{ij}(V_j V_i \;/ t_{ij})\sin(d_i^t - d_j^t + \alpha_{ij})$$

Section flow constraint (sum of active power flow through a number of power lines):

$$p_{st}^{\min} \le \sum_{(i,j)\in S}\left(dv_{ij} p_{ij}^{t} - (1 - dv_{ij}) p_{ji}^{t}\right) \le p_{st}^{\max},$$

Market participants registered at the Trading System Administrator (ATS) are allowed to bid for the capacity above minimum.

Minimum and maximum generation constraint:

$$P_{gt}^{\min} \le P_{gt} \le P_{gt}^{\max}$$

Integral constraint on min/max production during 24 hours:

$$P_{g}^{\min} \le \sum_{t=1}^{24} P_{gt} \le P_{g}^{\max}$$

Ramp-up/ramp-down constraint:

$$P_{g(t-1)} - n_g^{\min} \le P_{gt} \le P_{g(t-1)} + n_g^{\max}$$

Where c_g^m / P_g^m - generator offer (price/volume pair), c_c^m / P_c^m - demand bid(price/volume pair), p_{ij} - active power flow on line *ij*, t_{ij} - transformator on line *ij*, V, d - voltage and voltage angle, G_{ij} / Ω_{ij} - physical characteristics of power line conductance/susceptance, p_{st} - active flow through section, number of power lines predefined by SO, $n_g^{\min} / n_g^{\max}$ - minimum and maximum ramp rates. For more details on complete formulation of mathematical problem solved by ATS see Davidson et al. (2007).

Model 2. Transmission-Constrained Residual Supply Index

F is the set of firms of interest and *D* is the set of zones, where market participant is present. Model is solved for every hour in the analysed period separately, i.e. ignoring ramp-up/down constraint or integral constraint on hydro generation from model 10.1.

Objective function:

$$\max R_F$$

s.t.

Balancing constraint:

$$\sum_i p_{ij} + \sum_{g\,i} P_g = R_i P_c \;, \forall\, zones$$

Where R_F is transmission constrained RSI for firm F in zone $d \in D$, P_g - generation by RGE defined by ATS, P_c - consumption in the FFZ and p_{ij} - active power flow between the zones.

Constrains on R_F

$0.5 < R_d < 2$ – for all zones $d \in D$, where firm *F* is present

$R_z = 1$ – for all other zones $z \notin D$

Min/max constrains on transmission and generation:

$p_{ij}^{\min} \le p_{ij} \le p_{ij}^{\max}$ - minimum and maximum flow between the zones defined by the SO

$P_g^{\min} \le P_g \le P_g^{\max}$ - for all generators $g \notin F$

$P_g = P_g^{\min}$ - for all generators $g \in F$

Transmission-Constrained Residual Supply Index is defined separately for each firm *F* for each zone, where market participant is present.

Paper 4

REGULATORY OBSTACLES TO COMPETITION IN THE RUSSIAN POWER MARKET

Abstract

The purpose of the article is to describe the main regulatory challenges and obstacles to competition in the Russian power market, with emphasis on the role of the system operator (SO). Transmission constraints related to system security between the European and Siberian price zones led to enormous subsidization of the Siberian zone by customers in the European zone in the day-ahead electricity market. The regime and must-run generation avoid competition in the unit commitment (UC) auctions. The proposed elastic demand curve in the capacity market ignores high market concentration and reduces incentives for competition.

Key words: Russian power market, electricity, competition, regulation

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1 INTRODUCTION

In 2016, it will be 15 years since the launch of the liberalization of the Russian power market. At the same time, the day-ahead market (DAM) will celebrate its 10-year anniversary, and the capacity market will have been operating for five years. Ryapin (2013) characterizes the reform as successful in terms of creating a competitive wholesale market for electricity and capacity, and solving the issues associated with generation capacity. Nevertheless, according to Knyagin et al. (2014) and the Institute of Natural Monopolies (2013), the grid tariffs are improperly high, the sector still suffers from cross-subsidization, and ad hoc state intervention in the market increases the unpredictability and reduces the efficiency of the electric power sector.

Cooke (2013) and Chernenko (2015) analyse the degree of competition and market power in the electricity market in Russia. Gore et al. (2012) raise the question of whether the Russian power reform is a matter of deregulation or re-regulation of the electricity sector. This article sheds light on the most important regulatory obstacles to further competition, and discusses issues that are not necessarily related to market power.

How security constraints affect competition in the Russian power market has, to our knowledge, not been discussed in the literature, but these constraints represent non-transparent and potentially inefficient regulation of the degree of competition. Because security[1] and optimality are competing and contradictory requirements, it is not appropriate to treat them separately (Stott et al. 1986). In the Russian power market, the DAM is cleared as an optimal power flow (OPF) problem based on security constraints given by the system operator (SO). This can lead to obvious theoretical problems, which will be illustrated empirically in Section 2.

The SO sets the transmission and generation constraints for the DAM, partially estimates demand and defines regime generation in the UC auctions. At the same time, this entity also estimates demand, and defines regime/must-run units and transmission capacity in the capacity market. Obviously, the rules that allow market participants to avoid direct competition will be exploited and represent regulatory inefficiencies or indirect subsidies. Section 3 deals with priority dispatch of must-run generation in unit commitment (UC) auctions, illustrating how these power plants can avoid price caps in the DAM. Section 4 focuses on the recent changes in the rules for the capacity market. The changing in zoning from free-flow zones (FFZs) to price zones, along with the introduction of an elastic demand curve regulated by the Ministry of Energy and the SO, is not sufficient to deal with the market power of the dominating generators.

2 Transmission Constraints

The Russian DAM is formulated as a nodal security-constrained optimal power flow problem (SC-OPF). The SO sets the N–1 criteria for the security, based on the available information about the expected load and maintenance for both generation and

[1] The optimal power flow problem can be extended to include security constraints referred to as SC-OPF. The credible hypothetical contingency scenarios, represented as additional constraints in the problem, basically account for a series of “what if” situations. The purpose of SC-OPF is to keep the system secure and to output at an optimal level, even when one of those possible scenarios arises (Stott et al. 1986).

the grid. The UC three-day-ahead auctions aim to minimize the costs of the reserves necessary to cover expected load and potential outages. Based on the solution for the UC auctions, the SO sets the constraints for the DAM, where the trading system administrator (ATS) solves a deterministic SC-OPF. The maximum/minimum constraints on generation are set on hourly and daily production, i.e. the integral constraint on generation over a 24-hour period. The transmission constraints represented by the constraints on sections, i.e. the sum of active power flows through the number of power lines. For more details on the complete formulation of the mathematical problem solved by the ATS, see Davidson et al. (2009) and Davidson and Seleznev (2014) for a discussion of UC auctions.

The Russian power system is divided into two price zones, the European (1) and the Siberian (2). Figure 1 in Appendix 2 illustrates the average daily price in the European and Siberian zones from April 2012 to July 2015. Figure 2.1 illustrates the flows and constraints on section 10099 between Siberia and the Urals, called “Balance Siberia” which includes the power lines between Siberia, Kazakhstan and the Urals. As can be seen from Figure 2.1, no constraints were set for section 10099 after 15 August 2014. In addition, for most of the hours in the period between April 2012 and August 2014, the minimum and maximum constraints are negative, i.e. power flows from the Urals to Siberia. This implies that even if the balance situation and prices in Siberia should imply flows from Siberia to the Urals, an average of 680 MW would still flow in the opposite direction. This further pushed prices downwards in Siberia and upwards in the European zone, first and foremost in the Urals.

Pipkin (2014) describes time regularities of zonal prices and identifies the extreme price differences between the zones. The data on flows by power line were made public in 2015, which allowed confirmation of the direction of the flows through section 10099. As can be seen in Table 2.1, the price difference between the zones was 375 RUB/MWh in the period prior to August 2014 and 192 RUB/MWh thereafter. This corresponds to 54% and 21% of the Siberian price in the respective periods.

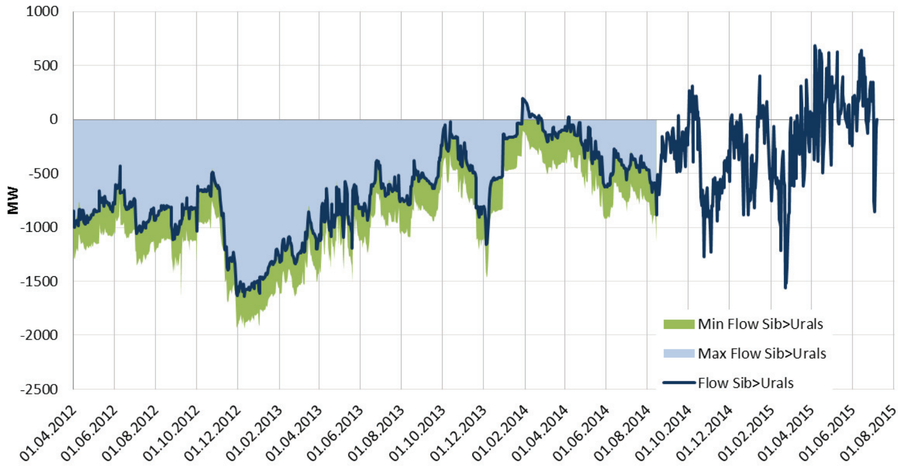

Figure 2.1 Max/min constraints and flows from the Siberian to the European zone

Notes: Blue and green areas represent max/min constraint on flows from Siberia to Urals in the European zone. Since 15 August 15 2014, the section has been unconstrained, i.e. limits at 9999/–9999 are not illustrated in the figure.

For 95% of the hours (19 745 of 20 784) in the analysed period prior to August 2014, the section was congested towards the Urals. The ATS publishes nodal prices for the largest 5000 nodes, and nodal prices in section 10099 linking Siberia and the Urals are available for the analysed period. We calculate the average price for the nodes on the Siberian side of this section, as well as an average for the Urals side[2]. The average price difference between the nodes in the section was 343 RUB/MWh prior to August 2014 and 88 RUB/MWh thereafter.

Table 2.1 Descriptive statistics on prices and congestion

Period		Zone 1	Zone 2	Urals nodes	Siberia nodes	No. of cong. hours Sib>Urals	No. of cong. hours Ural>Sib
01.04.12–07.07.15	mean	1077	752	1084	811	69%	0.4%
	std. dev.	214	155	189	186	-	-
01.04.12–14.8.14	mean	1068	693	1079	736	95 %	0.6%
	std. dev.	209	100	188	128	-	-
15.8.14–07.07.15	mean	1100	908	1097	1009	-	-
	std. dev.	226	167	193	171	-	-

[2] Section 10099 consists of 11 power lines with different voltages. By taking the average of the prices in the western and eastern parts of the section, I obtain the Urals and Siberian nodal prices of the section.

The locational-based marginal price (LMP) at a location is defined as the cost of supplying an increment of load. This price includes the cost of producing energy and delivery: losses and/or transmission congestion lead to "out of merit" dispatch to satisfy system constraints (Litvinov et al. 2004). LMP in bus *i* can be defined as:

$$LMP_i = LMP^{Energy} + LMP_i^{Losses} + LMP_i^{Congestion}. \qquad (1)$$

The loss component is given by a loss factor dependent primarily on the topology and balance in the node, multiplied by the energy component (LMP^{Energy}). Thus, the nodal price difference can be described by the deterministic component including time regularities, as described in Pipkin (2014), and a stochastic component represented mainly by the congestion. The simplified relationship between nodal prices can be defined as follows:

$$P_t^{Siberia} = \alpha + \beta_p P_t^{Urals} + \beta_{Max} D^{Max} + \beta_{Min} D^{Min} + \sum_{h=1}^{24} \beta_h HD_t^h + \beta_W WD_t + \varepsilon_t , \qquad (2)$$

where D^{Max}/D^{Min} are dummy variables for congestion to the Urals/Siberia regions on section 10099, HD^h are dummy variables for hour of the day, and *WD* represents a work-day dummy.

Using ordinary least-squares (OLS), one can estimate the relationship in equation 2 before and after 15 August 2014. Augmented Dickey–Fuller tests confirm that nodal prices are stationary. The estimated coefficients suggest that during the first period in the analysis, the correlation between the nodal prices was close to zero, whereas when flows on section 10099 to the Urals were congested, the price in the Siberian nodes decreased by 85 RUB/MWh. The coefficient for the minimum congestion dummy at section 10099 is negative, but not significant at the 5% level. All of the dummy variables for hour of the day (except at 4 am) and the work-day dummy are significantly different from zero in the first period. For the period after 15 August 2014, the relationship between the nodal prices was 0.77, whereas the coefficient for the dummy variables for the hours from 10 am to 8 pm and the work-day dummy are not significantly different from zero. The explanatory power of the model increases from 17% in the first period to 82% in the second period. See Table 1 in Appendix 2 for more details.

By running a rolling OLS regression with a window of 840 hours, one can illustrate the changes in the relationship between nodal prices in Siberia and the Urals. The

Gregory–Hansen test for structural breaks suggests that there is a break on 14 August 2014. The coefficients for the nodal price in the Urals from equation 2 are displayed in Figure 2.2.

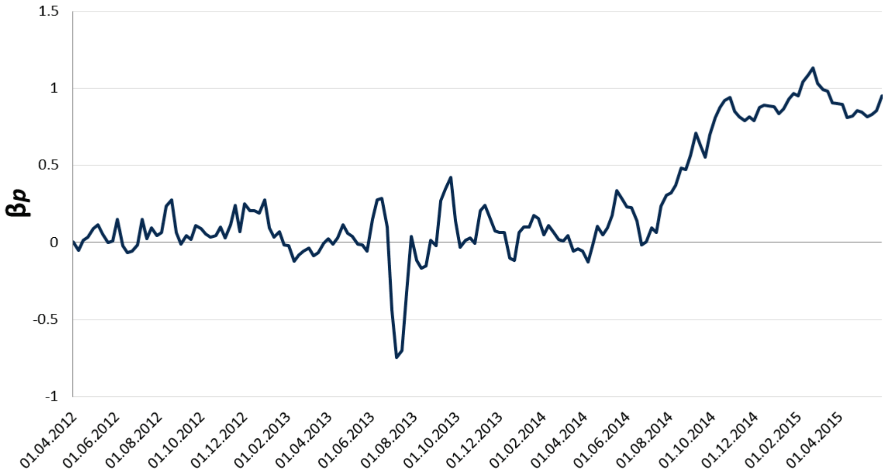

Figure 2.2 Rolling β_p coefficient in eq. 2 from May 2012 to June 2015

The ATS started to publish supply and demand curves for the price zones without linking bids/offers to market participants. We refer to the average price index for a price zone as the price in the respective zone, but the index is calculated by taking the average of the buy and sell indices for the zone. The buy and sell indices represent a volume-weighted average of nodal prices for the demand and supply nodes, respectively. The intersection between the price in a zone and the supply curve reflects demand and losses, but also the average congestion effect. Thus, zonal price indices can be treated as a volume-weighted average of the marginal generation offers for all nodes in the zone, because only generators' offers can clear the market.

Figure 2.3 displays supply curves for the price zones at 6 am on 27 May 2014. We can see that the price was 960 RUB/MWh in zone 1 and 680 RUB/MWh in zone 2, as indicated by the intersection between the supply curve and the green line. The maximum flow constraint and actual flows from Siberia to the Urals were both –1125 MW, i.e. in the opposite direction of this price relationship. We can find the effect of forced flows from the Urals to Siberia by moving the green line left/right by 1125 MW for zone 1 and zone 2, respectively. The new intersection represents a situation with no exchange between the zones, and is illustrated by a green dotted line in Figure 2.3. The price in zone 1 decreases by 50 RUB/MWh, and increases by 180 RUB/MWh in zone 2 in the new equilibrium. If we set the new maximum constraint on section 10099 to zero, the section flow would still hit the constraint because the price difference between the zones is still 50 RUB/MWh. In the new equilibrium, European consumers are not forced to subsidize Siberian consumers, but Siberian generators are not allowed to supply to zone 1.

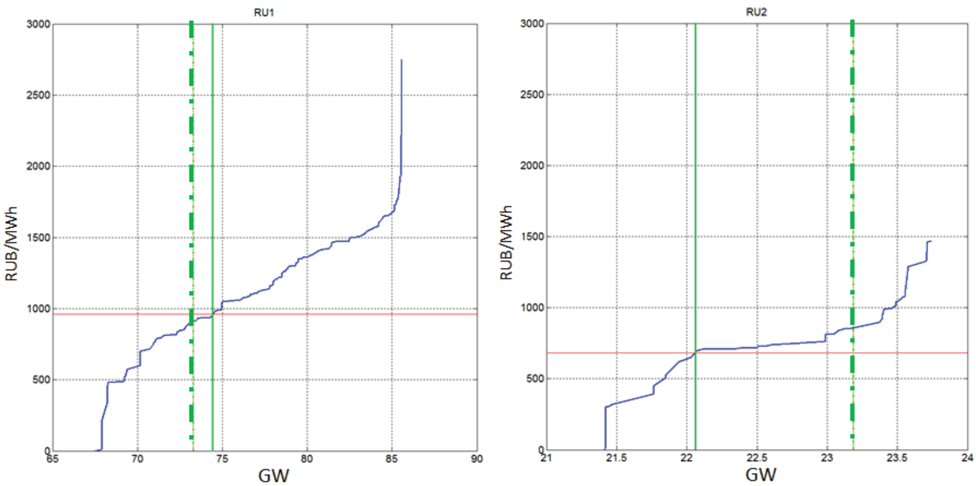

Figure 2.3 DAM supply curve in zone 1 and zone 2, at 6 am on 27 May 2014

Notes: The blue line represents the supply curve in the price zone, the intersection between the green and red lines shows the market equilibrium, and the green dash-dotted line illustrates the shift from equilibrium with forced flows to zero flows between zone 1 and zone 2.

We assume that the area around the intersection between the price and supply curves represents the average marginal effect of changing the balance situation between the zones, and I run a linear problem to minimize total costs subject to meeting the average of generation and consumption in each zone in order to achieve an equal distribution of losses. We assume max/min constraints on flows from Siberia to the Urals at 1216/–2044 MW, and ramp-up/down constraints at 450/–450 MW/hour for the whole period.

The simulation of market coupling between the zones leads to an average price decrease of 80 RUB/MWh in zone 1, and an average price increase of 320 RUB/MWh in zone 2, for the period from 1 January 2014 to 14 August 2014. In order to test the validity of this approach we run the same simulation for the period from 15 August 2014 to 31 May 2015 to control for potential errors (see Figures 1 and 2 in Appendix 2). The mean absolute percentage error for the price estimate for the second period is

8% for zone 1 and 10% for zone 2. This can be explained by the existence of other bottlenecks in transmission inside each zone, the non-linearity in the actual supply curves represented by the stepwise function and the distribution of the prices of losses. Nevertheless, the simulation illustrates that the mechanism where the SO sets security constraints ignoring market signals, has a huge impact on the market outcome.

The analysis suggests that the assumption of one market for the two zones in Russia is questionable prior to 15 August 2014, as there is little or no correlation in nodal prices at the borders between the zones. Market coupling between the two zones after 15 August 2014 leads to more efficient usage of transmission capacity between the zones. Further analysis also demonstrates that consumers in zone 1 paid up to RUB 6.8 million/hour in the period prior to 15 August 2014 for security in the Siberian zone, which corresponds to a similar loss of profit for generators as that in Siberia. Consequently, one can question whether the price for security can be justified, whether consumers in price zone 1 should subsidize Siberian consumers, and whether and how security issues should be solved in the market.

3 Unit Commitment Auctions

As previously mentioned, the UC three-day-ahead auctions play an important role in the Russian power market. Formally, this auction is not part of the market, but participation in the UC auctions is necessary to offer prices above zero in the DAM. In addition, the offers made in the UC auctions are used as price caps for offers in the DAM.

There are four types of market participants in the UC auction: regime units, must-run units, non-optimized units (nuclear and hydro) and optimized units. Optimized units, typically thermal power plants, can be turned on or off to minimize the total costs of meeting demand and spinning reserve requirements, including start costs and electricity generation costs. The SO defines regime units as units necessary to ensure security in the system. Must-run units are all other power plants needed in the system for reasons not related to the security of the system. A typical example is combined heat and power units, which supply heat to the local municipality. Nuclear and hydro power plants report the expected available capacity and maintenance schedule, whereas hydro capacity is used as a free resource for flexibility in the system. The UC algorithm aims to minimize total costs for the reserves and electricity, where the priority rank is defined as must-run units (1), regime units (2) and all other units (3).

The SO started to publish hourly supply curves in the UC actions for the price zones and federal subjects (oblast) in February 2014. There are three supply curves for each region: offers by regime, must-run units and all offers. Offers are expressed as volume–price pairs, where the curve for all offers includes regime and must-run offers, but with zero price. The solution includes regime and must-run offers by default, in addition to the other offers, which were optimal according to the algorithm. Nevertheless, regime and must-run units can offer prices above zero in the DAM, which raises questions about the optimality of this mechanism.

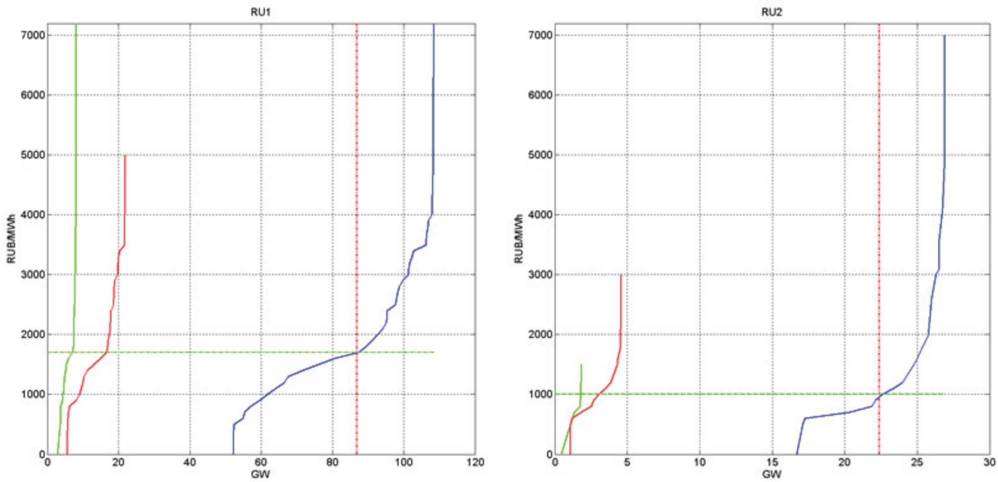

Figure 3.1 UC auction supply curve in zones 1 and 2, at 8 am on 16 July 2014

Notes: Green line illustrates offers by regime units, defined by SO. Red line illustrates supply curve of self-reported must-run units. Blue line illustrates all offers, with zero prices on volumes for regime and must-run generation. Red dotted lined illustrates the solution, i.e. accepted offers to cover demand and reserves. Horizontal green line illustrates system price in the region, i.e. the lowest bid for the same capacity.

In the period from May 2014 to May 2015, there was on average 119 GW of available generation in the European price zone, and 28.6 GW in the Siberian zone. This corresponds to the sum of all offers in the UC auctions, whereas the remaining installed capacity (230 GW in total) was under maintenance, or not participating in the auctions.

The actual solution, including reserves, was 96 GW and 24 GW on average, which is 11% and 4% above average demand in the two zones, respectively, during the analysed period. The regime units account for 5% of the total reserves in the European zone, and 3% in the Siberian zone. Must-run units account for 37% in the European zone, and 38% in the Siberian zone. It follows that only 60% of the reserves were actually part of the solution in the UC SC-OPF algorithm, whereas the remaining share was not part of the solution, but merely inputs into the model. Hydro and nuclear generation will have priority dispatch because of low costs compared with thermal generation; thus, the share of thermal units competing in UC auctions is only 30% of running capacity in the European zone and 17% in the Siberian zone. This is illustrated in Figure 3.2.

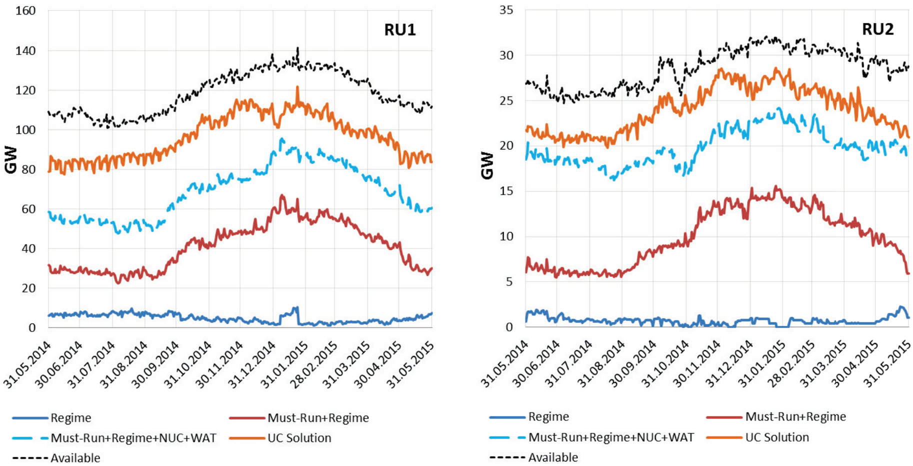

Figure 3.2 Share of available, must-run and regime units of solution in UC auctions

Notes: Black dotted line illustrates total available capacity in UC auction, blue line illustrates regime units, red line illustrates regime and must-run generation, blue dotted line illustrates must-run units, regime units, nuclear and hydro generation, and orange line illustrates the solution of the UC auctions, i.e. running capacity necessary to cover expected demand, losses and reserves.

By ignoring the priority rank of must-run generators, start costs, and the mixed-integer nature of the UC model, and assuming no congestion or loop flow, we can calculate the minimal offer for the same reserve as calculated by the SO. What would be the highest offer necessary to meet the same reserve requirement in the area, ignoring any constraints or system price in the area? The highest offer accepted by the SO was 17 600 RUB/MWh on average in zone 1, whereas the system price was 2725 RUB/MWh. For the Siberian zone, the actual average highest offer accepted was 12 500 RUB/MWh on average, whereas the system price was 1100 RUB/MWh. When the system price is identified, it is possible to calculate the share of must-run capacity with offers that are above the optimal level. Around 16%/24% of must-run generators

(6%/9% of total reserves) were bidding above the system price in the European/Siberian zone, respectively. The large difference between the highest offer accepted by the SO and the system price implies that must-run generators exploit their position by removing any possible price caps in the DAM, whereas approximately 19%/9% of the regime units (0.9%/0.3% of total reserves) were bidding above the system price. On the other hand, by providing bids that are several times above fuel costs, power plants communicate that they want to avoid participating in the DAM. As described in Paper 3 in this dissertation, the UC auctions can be used to remove capacity from the DAM in order to increase prices, or to avoid strict regulations of minimum and maximum generation that reduce the potential for market power in the DAM.

Similar results are found by analysing the federal subjects (oblast), as a volume-weighted average of must-run generation is 56% and regime units stand for 32% of the optimal solution. The volume-weighted average of the maximum accepted offers for all regions is 4350 RUB/MW, whereas the system price is 2800 RUB/MWh. The volume-weighted average of must-run generation with bids above optimal is 2.8% of the total, and 0.5% for regime-unit generation[3]. This implies that must-run capacity with bids above competitive levels represents a marginal share of total reserves analysed by the federal subjects (oblast). This result differs from the analysis on a price-zone level because of the fact that the system price defined for the federal subjects will include some transmission constraints that are not included in the calculation of system prices for the price zones. The difference also illustrates the fact that in some federal subjects there are no alternative supplies to must-run and regime generation. See Table 2 in Appendix 1 for more details.

By running inefficient heat power plants, the SO forces efficient thermal power plants in the cold reserve, out of the DAM. Consequently, inefficient must-run power plants allowed bidding significantly above competitive levels in the DAM. Future research should focus on the details of the interaction between the UC auctions and the DAM in Russia.

[3] 5% of must-run units and 1% of regime-units bid above calculated system price.

4 Capacity Market

The capacity auction takes place in the autumn prior to the year of delivery. The auction in the autumn of 2015 (for the year 2016) will also include auctions for 2017–2019. The SO defines transmission constraints between the FFZs and solves a zonal model to find the clearing price. Because of poor transmission constraints between FFZs and the dominant position of market players, the Federal Antimonopoly Services (FAS) has previously set price caps for the majority of FFZs in the capacity market. End-users pay for the capacity used during the preceding month, i.e. an ex post average of maximum consumption during peak hours of the working days during the previous month.

The situation with priority dispatch of must-run generation is also relevant for the capacity market. One could lobby for a priority status prior to or after the auction, and receive a tariff calculated individually by the Federal Tariff Service (FST), which is paid by the customers in the federal subject (oblast). The remaining market players compete for the residual demand for capacity, i.e. peak demand and reserves forecasted by the SO minus must-run/regime units and the capacity allocated through long-term capacity agreements (LTA).

New investment requirements are secured until 2018 through a contractual obligation placed on purchasing parties under the privatization process (the LTA mechanism) (Cooke, Antonyuk, and Murray 2012). The LTA volumes are included in the capacity market with price-accepting offers, but receive a separate tariff that is defined by the Ministry of Energy and the FST, and paid by the customers within a FFZ. All delays in commissioning new capacity through the LTA are penalized by the Ministry of Energy and the SO.

The SO defines peak demand and reserves, transmission constraints and regime/must-run units. The must-run status is the only solution for inefficient units that expect to be outside of the market. Because of the commissioning of new power plants through the LTA, in addition to new nuclear/hydro power plants of 7.6 GW in total and a decrease in the demand for peak capacity of 5.2 GW, the capacity of non-selected units increased from 3.4 GW in 2014 to 15.3 GW in 2015 in the UC auctions (Opadchiy 2015). This led to massive lobbying for must-run status, which could be acquired also after the auctions. In practice, the must-run generators avoided competition, whereas potentially competitive power plants did not receive capacity payments, which can account for up to 50% of total income for the generation companies.

The capacity auction for 2016 will be modified significantly to face the challenges of must-generation, congestion and excess capacity. Only power plants that have received must-run status previously can apply to renew their status prior to the auction. The changes will also take the excess capacity into account by introducing an elastic demand curve. The auction will be based on only two price zones, which will reduce the ability of generators to exert market power in the FFZs with low transmission capacity, as described in Paper 3 in this dissertation.

The Ministry of Energy defines the upper and lower price bounds for the two price zones separately, whereas the SO calculates the demand for capacity, i.e. minimum demand. See Figure 4.1 and Table 3 in Appendix 1 for more details. The upper demand is defined as including the 12% extra reserves[4] in price zone 1 and an additional 8.55% to deal with a potentially dry year for hydro generation in zone 2. Thus, the linear demand function for each zone is given by the two price–volume pairs. The transmission capacity between the zones is calculated based on the average of actual flows from December to February the previous year multiplied by 1.3 and equal to 755 MW. Exports and imports to other countries are defined in a similar manner, but without the 30% upward adjustment.

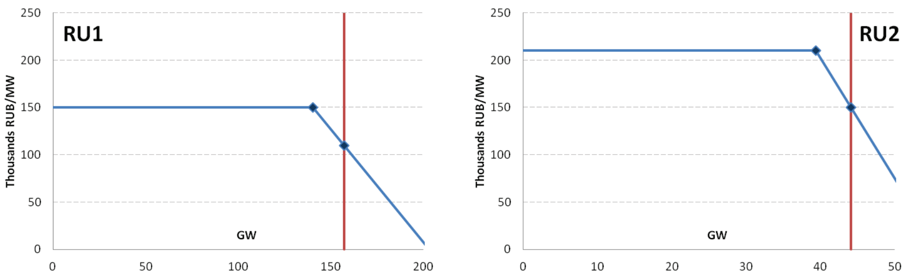

Figure 4.1 Elastic demand function and installed capacity in capacity market

The installed capacity in the European zone is close to the upper bound set by the SO at 157 GW. The lower bound in the Siberian zone is above the price cap in the European zone, which implies no exports from the Siberian zone to the European zone.

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[4] This is in addition to demand for capacity estimated by the SO.

Thus, the competition is still limited and the elastic demand is adjusted in such a way that all generators can receive the capacity payment if all parties bid below or at the lower bound.

Assume price-accepting firms and one dominant firm with installed capacity of 34 GW ($\approx 2 \times 17$ GW elastic part of demand curve in zone 1) with a marginal cost of 110 000 RUB/MW. The dominant firm will reduce the output to increase the capacity price up to the price cap, as illustrated in Figure 4.2. The marginal revenue function has a discontinuity because of the price cap at 150 000 RUB/MW illustrated in Figure 4.2. Coincidentally, the installed capacity of Gazprom is close to 38 GW, and the largest three thermal[5] generators in Russia control a total capacity of 71 GW. Assuming a marginal cost (long-run marginal cost for maintaining capacity) of 110 000 RUB, a Cournot oligopoly with three identical firms with a capacity of 67 GW (or above) can reduce their combined output to increase the price up to the price cap of 150 000 RUB in the European zone. It is also easy to illustrate that for a dominant firm with approximately 50 GW (or more) of installed capacity and zero marginal costs[6], it is profitable to withdraw capacity from the market up to the price cap. See Figure 3 in Appendix 2.

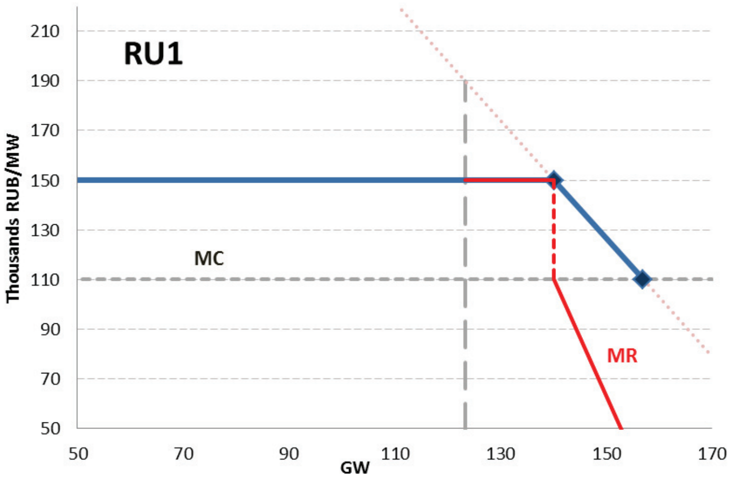

Figure 4.2 Residual demand function and marginal revenue for a dominant firm with installed capacity of 34 GW and price accepting supply of 123 GW

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[5] Ignore RusHydro and RosEnergoAtom.
[6] All fixed costs are sunk costs if, for example, it is not possible to decommission a power plant. Otherwise it is possible to have negative marginal costs for capacity if primary income comes from, for example, heat generation.

In the short term, the capacity of market participants is given and they compete on price; thus, a Bertrand solution and no stable Nash equilibrium exists if $MC = 0$. Nevertheless, if all market participants bid below 110 000 RUB, i.e. all offers will be accepted and thus the price will be at 110 000 RUB assuming the lower bound equals total available/installed capacity. In this case, it is profitable for all minor firms with marginal costs below 150 000 RUB/MW to bid below 110 000 RUB/MW, because it is always profitable for Gazprom to withdraw their capacity to hit the price cap. All offers above 150 000 RUB/MW are excluded from the auction.

By introducing the new rules in the capacity market, the regulators successfully constrained the lobbying for must-run generation, and hence reduced the level of subsidies for heat generation. The new model deals with the necessity for price caps for 21 of 23 FFZs with poor competition, previously regulated by the FAS. In addition, regulators acknowledged the problem of excess capacity through the introduction of elastic demand for capacity.

The introduction of price zones instead of FFZs in the capacity market is not sufficient to deal with market concentration, whereas the slope of the elastic demand curve allows execution of market power up to the price-cap level. The SO assumes 0.75 GW transmission capacity between the zones which, in addition to the level of the price floor in the Siberian zone, implies that a significant price difference between the zones will also remain in the capacity market.

5 Conclusions

Since the introduction of market coupling between the two price zones in August 2014, the DAM can be characterized as a functioning market, with the exception of the remaining 10–20% of residential demand that still receives FST tariffs. There are still issues to be solved when it comes to the transparency of the UC auctions that set constraints for competition in the DAM. It is difficult to see any reason why inefficient heat power plants should be allowed to avoid competition in the UC auctions, and price caps in the DAM. The capacity market can by no means be described as liberalized, and appears to be a regulated, potentially inefficient and inflexible way to finance new capacity and maintain existing generation. At present, the ad hoc regulations lead to unstable market rules, where consumers and generators bargain with the government and regulators for potential profits. The remaining cross-subsidies constrain further development of the industry, and lead to inefficiencies between heat and electricity/capacity markets. These issues can only be resolved through the competitive pricing of heat generation.

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Appendix 1. Tables.

Table 1 Regression results from equation 2

Coefficient	01.04.12-14.8.14	15.8.14-07.07.15
constant	711**	172**
price Urals	0.005	0.768**
max constr	-85**	-
min constr	-26	-
hour_1	23**	-30**
hour_2	4	-19**
hour_3	-8**	-12**
hour_5	27**	15**
hour_6	45**	22**
hour_7	74**	39**
hour_8	101**	36**
hour_9	120**	30*
hour_10	120**	15
hour_11	126**	14
hour_12	133**	17
hour_13	127**	18
hour_14	122**	18
hour_15	107**	11
hour_16	111**	12
hour_17	119**	13
hour_18	113**	18
hour_19	126**	14
hour_20	142**	-7
hour_21	133**	-36**
hour_22	99**	-58**
hour_23	71**	-54**
hour_24	35**	-43**
workday	21**	-10
R2	0.15	0.82
DW	0.32	0.48
Nobs	20784	7848

*The 5% significance indicated by *, 1% by ***

Table 2 Average reserves, avail.capacity, must-run and regime units

Zone:	Consumption (GW)	Reserves (GW)	Available capacity in % of reserve	Must-Run	Regime Units	Other Accepted	Must-run above OptBid	Regimi above OptBid	Max Accepted Bid	Optimal Bid
RU1	85986	96278	124 %	37 %	5 %	58 %	6 %	0.9 %	17606	2725
RU2	23179	24023	119 %	38 %	3 %	59 %	9 %	0.3 %	12533	1096
ALT	1236	955	125 %	94 %	3 %	3 %	4 %	0 %	3324	2144
KDA	2891	1539	109 %	34 %	38 %	28 %	1 %	1 %	9864	7774
KYA	4745	8429	106 %	59 %	40 %	1 %	1 %	0 %	2986	1252
STA	1085	3016	109 %	10 %	13 %	77 %	0 %	0 %	6470	5298
AST	488	541	112 %	55 %	14 %	31 %	1 %	0 %	5381	5333
BEL	1707	93	141 %	100 %	0 %	0 %	4 %	0 %	2779	2594
BRY	508	4	105 %	100 %	0 %	0 %	0 %	0 %	2520	2520
VLA	781	295	165 %	88 %	4 %	7 %	4 %	0 %	3078	2921
VGG	1719	3007	112 %	56 %	43 %	1 %	1 %	0 %	7710	6414
VLG	1540	1718	114 %	51 %	35 %	14 %	2 %	0 %	4256	1781
VOR	1205	3184	102 %	52 %	47 %	0 %	0 %	0 %	2641	2581
NIZ	2301	1260	144 %	79 %	13 %	8 %	10 %	1 %	4456	3834
IVA	405	200	272 %	74 %	1 %	24 %	10 %	0 %	3437	3273
IRK	5976	10377	111 %	55 %	43 %	3 %	2 %	0 %	1100	724
TVE	968	8531	110 %	47 %	42 %	11 %	1 %	0 %	3408	2457
KLU	746	35	183 %	57 %	43 %	0 %	3 %	0 %	1298	1017
KEM	3644	3142	123 %	75 %	16 %	9 %	6 %	0 %	4176	2120
KIR	848	725	127 %	84 %	8 %	8 %	2 %	0 %	3568	3147
KOS	433	2339	129 %	44 %	1 %	54 %	4 %	0 %	4904	2687
SAM	2703	3983	123 %	71 %	28 %	1 %	5 %	0 %	4332	3587
KGN	510	397	135 %	82 %	0 %	18 %	2 %	0 %	1799	1744
KRS	980	7208	104 %	51 %	49 %	1 %	2 %	0 %	2609	2527
LEN	5035	10246	123 %	56 %	35 %	8 %	2 %	0 %	2985	1630
LIP	1400	1001	136 %	57 %	41 %	2 %	0 %	0 %	3327	3172
MOS	11354	9233	148 %	73 %	12 %	15 %	3 %	1 %	6096	2603
MUR	1451	3781	113 %	51 %	49 %	0 %	8 %	0 %	1146	1128
NGR	471	232	151 %	28 %	10 %	62 %	3 %	0 %	1196	1070
NVS	1793	1768	121 %	62 %	14 %	24 %	1 %	0 %	2507	1981
OMS	1269	1005	117 %	94 %	3 %	3 %	2 %	0 %	8952	8481
ORE	1782	2348	121 %	52 %	24 %	23 %	5 %	2 %	4276	3717
ORL	311	167	183 %	96 %	3 %	1 %	1 %	0 %	2036	2007
PNZ	572	185	201 %	85 %	12 %	3 %	2 %	1 %	3008	2914
PER	2704	4487	108 %	65 %	21 %	14 %	1 %	0 %	4003	3306
PSK	245	189	134 %	96 %	0 %	4 %	0 %	0 %	1236	1236
ROS	2048	6463	107 %	38 %	34 %	28 %	1 %	0 %	9883	7327
RYA	739	1154	239 %	58 %	0 %	42 %	19 %	0 %	2304	1653
SAR	1538	9083	119 %	53 %	47 %	0 %	2 %	0 %	3632	3457
SVE	4928	5992	116 %	52 %	26 %	22 %	3 %	2 %	5119	3367
SMO	739	6061	106 %	51 %	49 %	0 %	0 %	0 %	4412	3943
TAM	394	177	163 %	92 %	6 %	2 %	0 %	0 %	2625	2560
TUL	1139	898	242 %	70 %	15 %	15 %	12 %	0 %	3890	2778
TYU	10601	12295	107 %	47 %	17 %	36 %	2 %	0 %	5018	2018
ULY	671	456	162 %	89 %	11 %	0 %	2 %	0 %	3503	3454
CHE	4104	3478	117 %	60 %	28 %	12 %	2 %	1 %	4592	2019
ZAB	888	1026	120 %	54 %	19 %	27 %	1 %	0 %	1420	1211
YAR	914	435	148 %	78 %	20 %	2 %	7 %	0 %	4751	4364
BA	3009	2877	124 %	57 %	17 %	26 %	6 %	0 %	5849	2589
BU	619	718	153 %	32 %	39 %	29 %	12 %	2 %	1491	729
DA	693	799	100 %	50 %	50 %	0 %	0 %	0 %	5388	5388
KL	60	1	108 %	1 %	0 %	99 %	0 %	0 %	798	798
KR	869	906	103 %	59 %	41 %	0 %	0 %	0 %	1533	1533
ME	300	163	128 %	76 %	19 %	5 %	1 %	0 %	2972	2964
MO	379	268	138 %	76 %	21 %	4 %	2 %	0 %	3399	3313
TA	3085	2991	164 %	81 %	11 %	8 %	21 %	1 %	17450	4014
TY	85	9	347 %	43 %	48 %	9 %	0 %	0 %	526	526
UD	1095	620	115 %	85 %	13 %	2 %	1 %	0 %	3169	3096
KK	1929	4876	101 %	52 %	47 %	1 %	0 %	0 %	1412	1311
CU	587	766	130 %	68 %	24 %	8 %	3 %	0 %	3614	3406

Table 3 Definition of demand function for price zones in Capacity market

	European zone		Siberian zone	
	GW	Price (RUB/MW)	GW	Price(RUB/MW)
Upper bound	140.158	150 000	39.369	210 000
Lower bound	156.977	110 000	44.093	150 000

APPENDIX 2. FIGURES.

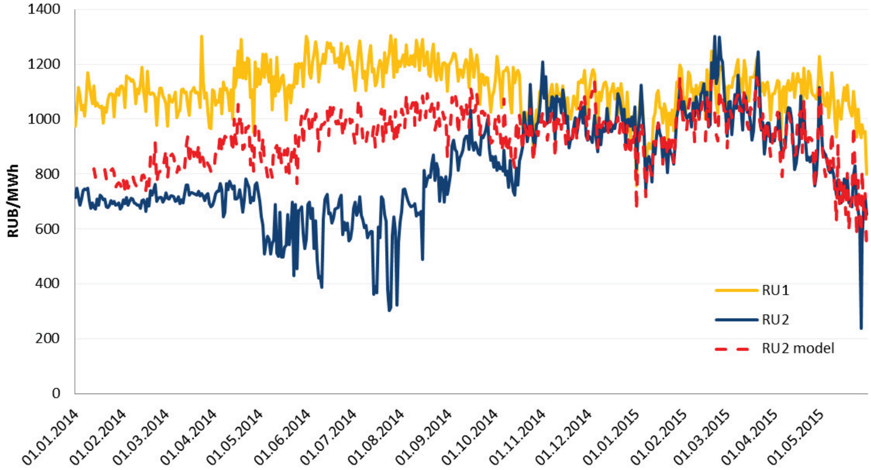

Figure 1 Daily average of simulated price in zone 2 and actual zonal prices

Notes: The simulation based on the supply curves for every zones allowing for optimal flows limited to 1200/-2000 MW from Siberia to Urals and ramp-up/down constraint 450/-450 MW for the whole period.

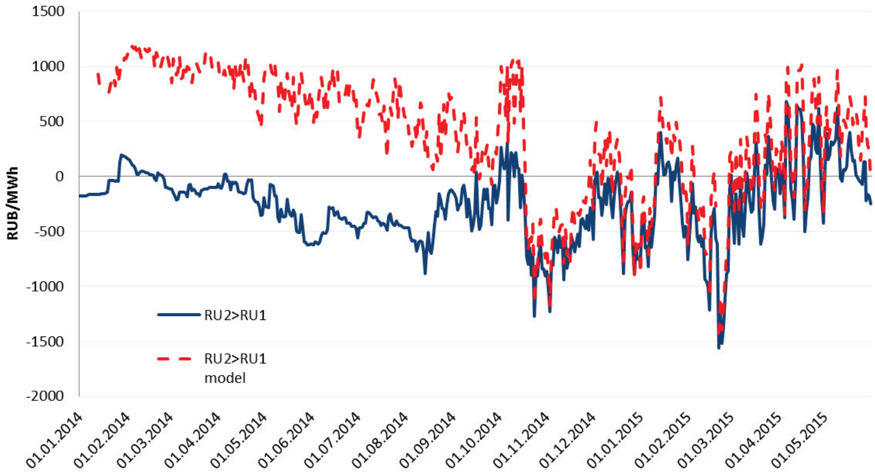

Figure 2 Daily average of the actual and simulated flows between the zones

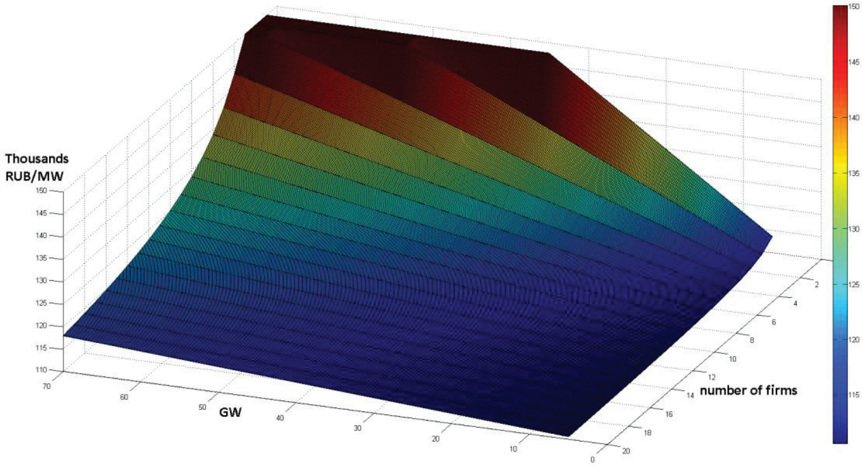

Figure 3 Cournot price as a function of number of firms and available capacity

APPENDIX 3. MODELS.

Model 1 Locational Marginal Price

$$LMP_i = \lambda + LF_{W:i}\lambda + \sum_{k=1}^{m} t_{w:i,k}\mu_k$$

, where λ is shadow price for the energy balance equation, μ is shadow price for the transmission constraints, LF_W – loss sensitivity vector, whose elements are calculated with respect to the slack reference represented as vector W, $t_{w:i,k}$ is the constraint k's power flow sensitivity to the injection at node i with respect to the slack reference W, and m is the number of constraints. (see more in Litvinov et al. 2004; Bo 2009; Li 2011; Li 2007; Li and Bo 2007; R. D. Zimmerman and Murillo-s 2011; R. D. Zimmerman, Murillo-s, and Thomas 2009; R. Zimmerman 2010)

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Igor Pipkin was born in Russia in 1980. He holds a MSc degree in Economics from the NMBU School of Economics and Business.

The dissertation consists of an introductory part and four self-contained papers. All the papers are sole-authored.

During the past decade the Russian power sector has undergone a dramatic reform. This has created a need for better understanding of the drivers and development of the sector. This dissertation describes the functioning of the Russian power market since 2006 by focusing on price formation, market power and the main regulatory obstacles for competition.

Paper 1 concludes that investments in new generation should take into account the magnitude and persistence of time regularities to reduce price difference between peak and off-peak hours. Similarly, the analysis of investments in transmission should focus on allowing greater exploitation of energy resources in Siberia. Papers 2 finds evidence of market power in the spot market, significant price elasticity of demand from Finland/Baltic states and shows the importance of price for natural gas for price for electricity in Northwest Russia. Paper 3 discusses the role of market rules and transmission capacity for exercise of market power in the Russian electricity and capacity market. Paper 4 summarizes the main regulatory obstacles for competition, subsidies from electricity to heat generation and no incentives for competition in the proposed model for the capacity market.

On the basis of these findings, he presents the following policy recommendations: facilitate consumer response to variation in electricity and capacity prices and invest in flexible technology on supply or demand side; upgrade the existing transmission capacity to discourage the exercise of market power and to deal with the supply security concerns; introduce competitive pricing of heat and fuel (natural gas and coal).

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