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.Keywords Russian electricity market, liberalisation, market power, concentration, price-cost mark-ups

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1. Introduction

In many electricity markets around the world, restructuring and liberalisation led to higher market power (as measured by the price-cost mark-up).[1] By contrast, we argue that in Russia a similar electricity market reform conducted in 2003-11 did not translate into higher price-cost mark-ups. This is especially surprising given a merger wave that followed soon after the industry restructuring and historically low volumes of contracting in the electricity markets. In this paper, we investigate the dynamics of market power in the post-reform Russian electricity market and discuss how the Russian government handled the issues of competition and potential market power abuse. We observe that the actual exercise of market power has been quite low and attribute the result to the bid-at-cost rules enforced via a special unit commitment procedure on the day-ahead market.

The Russian electricity industry reform consisted essentially of two components. The first component was divesture of the vertically integrated monopoly into generation and transmission companies and was largely completed in mid-2008. Further wave of mergers

[1] Most notable examples are England and Wales early 1990s (Wolfram 1999) and the California electricity crisis (Borenstein et al. 2002).

among the generators narrowed down the pool of owners in the industry, which suggests stronger potential for market power and higher price-cost mark-ups. The second component was market liberalisation with the removal of regulated contracts and tariffs and was finished by January 2011. Regulated contracts were by nature vesting contracts; their removal from the market meant lower contract cover, stronger incentives to exercise market power and higher mark-ups. In order to prevent price manipulations in the liberalised market, the government imposed the bid-at-cost rule on the generators requiring them to bid all available capacity at variable production cost[2].

On the Russian electricity market, the bid-at-cost rule is a part of the unit commitment procedure and the day-ahead trading. The unit commitment (UC) procedure is run by the System Operator on Friday; for Saturday until following Friday inclusive. The generators submit the start-up cost and price-quantity bids for all available capacity for the whole week. The procedure determines only the start/stop time of the generation equipment for the following week, not the output schedule. The UC price-quantity bids are used on the day-ahead (DA) market as self-enforcing price caps. On the DA market the generator may submit new bid (which would determine the actual hourly production) but the DA bids cannot exceed the UC bids. If a generator submits high UC bids he risks being idle for the next week, and if he submits high DA bids he will be capped with his own UC bids. The Federal Antimonopoly Service of Russia monitors the bidding behaviour and may inflict fines on companies suspected of manipulating the bids (as was already the case with several companies).

International research suggests that in liberalised markets private generators use capacity withholding as a typical strategy to exercise market power.[3] A large producer with several power plants would withhold some capacity so that a more expensive power plant comes into operation (that otherwise would remain idle) and determines a higher price on the market. The actual level of market power is measured by the price-cost mark-up, where price is usually a system marginal price and cost is the system marginal cost of generation. Since capacity withholding leads to higher mark-ups (the change in mark-ups depending of the slope of the supply curve), detecting excessive mark-ups becomes a tool to identify market power.[4] Theoretical results by Allaz and Vila (1993) show that contracting can drive price-cost mark-

[2] The rule to bid all available capacity is stipulated in Regulation 5 of the Market. Fixed cost of production is recovered separately on the capacity market.

[3] Bower et al. (2001) – the German market; Borenstein et al. (2002) – the Californian market; Buhn and Oliveira (2003) – the England and Wales market.

[4] Of course, one should exclude other reasonable explanations for insufficient capacity supply and the resulting high mark-ups; for example, extreme weather conditions (hence excessively high demand), a transmission line failure or other major technical accident, amongst other factors.

up down to zero. A regulatory requirement to bid at marginal cost may be another tool to keep mark-ups low (such a requirement exists, for example, on the Irish electricity market).

In Russia, where pre-reform regulated tariffs on electricity were kept artificially low, mark-ups would naturally be negative. Market liberalisation should lead to price rises, ideally up to the level of generation cost, and mark-ups would increase from negative values to zero. In other words, this increase in mark-ups that follows liberalisation does not immediately signal market power abuse. Rather, an increase beyond zero (or some other threshold level) would testify against market participants suspected of market power abuse.

Geographically, the Russian electricity market consists of 28 free flow zones defined by the major transmission lines so the market is quite fragmented. Within the zones trade is unrestricted while interzonal trade is subject to transmission constraints. The (already mentioned) post-reform merger wave concerned the companies located in different zones so at first glance the mergers did not affect the local level of concentration (though the situation might change when some smaller zones are incorporated with each other in the next few years). Bilateral contracts on the market have never been popular, constituting only 5-10% of the traded volume.[5] In a situation where contracts are not widespread, the requirement to bid all capacity at production cost was introduced on the Russian electricity market in order to curb market power and keep the mark-ups at a low level.

The Russian electricity supply industry went through a large restructuring reform in 2003-2011. The reform consisted essentially of two parts: restructuring the incumbent monopoly called RAO EES and redesigning the electricity market. The monopoly was separated into many generation companies, grid companies and the system operator. The new market trading rules introduced the commercial operator as well as free pricing and contracting, so that tariff regulation was eventually abandoned. The transition to free pricing started in January 2007 and took four years to complete. From January 2011, wholesale markets have been liberalised.

In parallel to these two aspects of the reform, our paper focuses on two main issues of market power: concentration and mark-ups. Analysis of concentration provides insight on long-term perspectives of market power, whereas dynamics of mark-ups illuminate the short-term perspective.

Two papers have already examined concentration on the Russian electricity market by computing the zonal HHI, which turned out to be relatively high. Pittman (2007) used the

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[5] Author's estimate based on hourly data from the ATS, Commercial Operator of the Russian Electricity Market.

industry structure and market zoning proposed at the start of the reform to compute the HHI index, while Gore et al. (2012) compute the index using the actual free flow zones. Neither of the papers accounted for transmission flows between the zones which can be quite significant as compared to intra-zone production. As a part of our study, we re-estimate the HHI given the final industry structure, ownership and import flows into FFZ. We find that concentration is severe in some parts of the country, whereas it is quite low in others. Mergers and acquisitions seem to have little impact on HHI as the merging companies were located in the different zones. The imports into some FFZ act as a significant 'competitor' to producers inside the zone and hence the overall situation with concentration appears less severe. We observe that reducing the number of zones and alleviating transmission constraints (and unlocking small zones) could significantly improve competition in the smallest zones of the market.

During the transition period to the free market, the government maintained electricity tariffs at a low level, and did not increase them to match production costs. In such a case, it is natural to expect an increase in prices and mark-ups once the regulation is removed; the size of increase depending on the discrepancy between the tariffs and the actual generation cost. Furthermore, regulated contracts represent a type of vesting contracts used in other countries to curb market power. Removing compulsory contracting creates stronger temptation to manipulate spot prices and, as such, could lead to higher mark-ups.

In our paper we estimate price-cost mark-ups in the Russian electricity industry during 2010 and 2011, namely a year preceding and following the market liberalisation on January 1, 2011. The mark-ups appear to be low and stable which contradicts the hypotheses of stronger market power due to concentration or removal of contracts. We also use a Tobit regression to quantify the impact of the regulated contracts and other counterfactuals on the mark-up dynamics. Our main finding is somewhat surprising: removing price regulation ***de***creased the mark-up by about 1.66 percentage points. We attribute the seeming discrepancy to the bit-at-cost rule implemented in the unit commitment procedure and in the day-ahead trading.

The rest of the paper is organised as follows: section 2 presents a brief historical overview of the Russian ESI; section 3 discusses theoretical measures of market power; section 4 focuses on ownership and concentration in the Russian market; section 5 deals with mark-up measures such as the Lerner index, the contracts and the impact of the liberalisation on the Lerner index dynamics.; section 6discuss the results and section 7 is the conclusion.

2. Russian electricity supply industry – historical overview [6]

This section reviews briefly the main features of the pre- and post-reform industry, with a focus on market design, concentration and pricing affecting market power. The pre-reform industry was essentially a vertically integrated monopoly, under heavy price regulation, but endowed with dispatch function which the monopoly abused to exercise market power and earn excessive profits. The post-reform market has problems with market power that are more similar to those in other developed and reformed electricity industries.

The Russian electricity supply industry in the early 1990s preserved many features of the planned system. The Soviet electricity industry consisted of 72 regional administrations called *energos*, each responsible for generation, distribution and supply in a given area. Total industry capacity in 1992 was 213 GW (Russian Statistics Service). At an early stage of the reforms, the federal government transferred the bulk of generation assets under the ownership of the newly created a holding company called RAO EES. The process of corporatisation was not smooth, since many regional authorities disputed control and ownership of the assets. The final property structure thus reflected the individual trade-off and compromise between the federal and regional governments. By 1996 RAO EES owned, controlled or managed nearly 168 GW out of 213.[7] Some of the regional generation companies managed to defend their independent status: together they owned 26 GW. Nuclear power stations (21 GW) were managed separately under the umbrella of the state agency for nuclear generation.

The subsidiary companies of RAO EES and independent producers were still responsible for electricity supplies in their areas. To manage imbalances in local supply and demand, the government created a federal market for electricity and capacity (called FOREM) and assigned the role of market and dispatch operator to RAO EES. This inevitably led to inefficiency and a conflict of interest, because RAO EES was interested in dispatching its own power plants first, that were relatively expensive to run (e.g. thermal power plants), rather than power plants of the independent producers with low variable cost (e.g. hydropower generation).

The financial situation in the industry was quite poor. First, the general economic situation was not favourable to the industry: the economy was declining and so was the demand for

[6] This section is largely based on IEA report (1993, 1995) and the book by Xu (2004). See Opitz (2000) for an interim review; Kennedy (2003) and Tompson (2004) for a brief summary of the reform; Solanko (2011), Gore et al. (2012) and Chernenko (2013) for a more detailed discussion of the reform.

[7] RAO EES (1996) annual report. Total industry capacity increased by only 3 GW from 1992 to 1996.

electricity. Annual consumption dropped by 23%, from 1068 TWh in 1991 to 826 TWh in 1998; however, power plants were hardly ever shut down and the reserve margin was growing. Probably the main reason is that almost half of thermal station stations are combined heat and power plants (CHP), which produce heat for local residential customers and cannot be mothballed completely.

Second, for political and social reasons, the government maintained price regulation in the electricity industry. Low household tariffs were subsidised at the cost of higher tariffs for industry customers (see IEA reports 1993, 1995). The problem of cross-subsidy appears extremely sensitive as it was not resolved during the last reform: with the liberalised wholesale prices, the low household tariffs are now cross-subsidised through higher distribution tariffs for industrial customers.[8] Finally, the problem of low tariffs was aggravated by non-payment problems: in 1997 RAO EES collected as little as 6-7% of the electricity bill in cash,[9] the rest being paid in form of promissory notes, offsets and barter (a typical problem for post-soviet countries; see Krishnaswamy, 1999). Combined together, low demand, low tariffs and non-payment problem translated into constant financial losses in the industry.

The scenario of economic recession and a high reserve margin, combined with government policy of low tariffs, resembles the experience of other developing countries not only in the former Soviet Union but also in Latin America, such as Argentina or Colombia.[10] In Russia, the 1998 financial crisis reversed the economic situation from deep depression to recovery and subsequent growth, however the problem of low tariffs was only partially resolved during the liberalisation reform in 2000s.

In terms of market power, the industry structure that emerged by the mid-1990s seems quite peculiar. The dominant monopoly could not manipulate tariffs, yet it had an opportunity to manipulate dispatch schedules, thereby ensuring positive profits (or smaller losses) for itself and its subsidiaries. The Russian case seems to be atypical as other electricity markets and jurisdictions have (or had) a *single* vertically integrated monopoly or at least an *independent* system operator.

General dissatisfaction with poor industry performance, coupled with the economic revival in the late 1990s, provided the background for industry reform. After heated discussions, in 2001

[8] The distribution charges for industrial customers are modified through the so called last-mile contract; see Chernenko (2013), section 6.3 for more details.
[9] Source of figure: Xu (2004), page 309.
[10] Dyner et al. (2007).

the government adopted a programme of complete restructuring of the monopoly and of establishing competitive markets (rather than minor modifications of the monopoly or market design). During 2003-2006 the monopoly and its dependent energos were re-grouped into 21 generation companies.[11] The transmission division was singled out as the Federal Grid Company FSK, and the distribution divisions formed a company called Holding MRSK. The dispatch division became an independent System Operator, while the Commercial Operator was created from scratch. The independent power producers were also required to separate generation and distribution, and create independent companies.

For the purpose of market operation, the country was divided into two pricing areas, ‘Europe’ and ‘Siberia’, and was further subdivided into free flow zones (FFZ).[12] The FFZs are defined on the basis of major transmission constraints (i.e. the zones were defined ex ante to the market dynamics, price differentials, etc.) There are six FFZ in the ‘Siberia’ price area and 22 in the ‘Europe’ price area.[13] The electricity market is based on nodal pricing, whereas the capacity market relies on zonal pricing. In both markets trading between FFZs is restricted due to transmission constraints. Market zoning and composition of the new generation companies (i.e. size and location of their power plant) and translates into uneven concentration level across the country and the potential for market power abuse.

There are currently two types of companies: wholesale and territorial. A wholesale generation company, WGC, has large power plants that are dispersed across the country, so as to avoid concentration of assets in a small area. There are eight WGCs, two of them under direct state ownership. One company became the owner of all nuclear power plants (23 GW in total); the other one received all major hydropower plants in the industry (24.5 GW). The six remaining companies, each between 8.3-9.2 GW, have large thermal power plants only. A territorial company, TGC, has small power plants, CHP and sometimes small hydropower stations; it is located within few administrative regions. Initially there were 14 territorial companies (some of them later split up into smaller entities): their size varied greatly from just 600 MW up to 12,880 MW.[14]

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[11] Six wholesale companies, 14 territorial companies and one hydropower company (details in the main text). Nuclear generation was, and remained, under separate state control.

[12] There are two non-pricing areas: one at the north of the European part of the country; the other one at the Far East. Both remain under government regulation. Together they account only for 5% of the capacity and total demand (author’s estimate) and their operation hardly interfere with that of the main markets.

[13] In 2013, and subsequently in 2014, some small FFZ are integrated with their larger neighbours, the total number of zones in the ‘Europe’ price area is reduced from 22 to 18.

[14] The size of the industry increased from 213 GW in 1992 to 225 GW in 2005 (Russian Statistics Service). The bulk of capacity is in the price zones; the non-price areas account only for 5% of the total figure.

The privatisation of the generation companies aimed at creating a pool of competitive investors. The process was largely complete by the end of 2006. However, the final ownership structure appears quite concentrated given the small number of Russian holding companies, in particular Gazprom the gas monopoly, and a small number of foreign investors among the owners. Further mergers and acquisitions that inevitably followed in the industry threatened competition in the market and challenged the basic principles of the reform.

The new wholesale market for electricity and capacity, NOREM (based on free bidding and free contracting) began operating in 2006. From January 2007 the government reduced gradually the volume of electricity to be sold under the tariffs (equivalently, under regulated contracts).[15] Since January 2011 the wholesale markets have been liberalised (with bidding rules in place), and the government restricts tariff regulation to prices for households. There was general agreement that the tariffs were too low to cover production costs, so after the transition period the prices were expected to increase in order to align with cost.

The main element of the liberalisation was a regulated contract that stipulated both the amount and the price (tariff) of electricity for sale or purchase. The regulated contracts resembled the vesting contracts used in other countries such as England & Wales to smooth transition from the regulated industry to a free market. As for the free bilateral contracts on the Russian liberalised market, these do not appear to be popular, in 2011 their gross share in the traded volume was only 5% (and the figure did not change much in 2012).[16] Theory predicts that in such cases market players have stronger incentives to exercise market power as their sales and revenue are directly linked to spot prices.[17] (The issue of contracts is discussed in greater detail in Section 5 on contracts and mark-ups).

A special feature of the market design is a general requirement for generators to bid at full production cost.[18] The generator should include the relevant variable cost of production, in particular fuel expenses. Fixed cost (such as maintenance expenses, capital cost, etc.) is recovered on the capacity market. A similar requirement of bidding at short-run marginal cost exists, e.g., on the Irish Electricity Market where the cost includes among others items the start-up and no-load cost.[19] In Russia, start-up cost is taken into account during the weekly

[15] Government Decree N 205 issued on 07.04.2007.
[16] Source of figures: author's estimate based on data from the Commercial Operator ATS.
[17] Allaz and Vila (1993), although others dispute the results, see Murphy and Smeers (2010).
[18] See Government Decree N 1172 issued on 27.12.2010, "On the Rules of the Wholesale Markets for Electricity and Capacity", Article 18 of the Rules.
[19]Bidding Code of Practice (2007), Single Electricity Market Operator (Ireland), available at [www.allislandproject.org/GetAttachment.aspx?id=6ce5b381-927e-4e4f-8642-341d53985720]

unit commitment procedure while main bidding takes place on the day-ahead market. The bidding behaviour is monitored by the Federal Anti-Monopoly Service who had already issued decisions and inflicted fines on TGC-11 in 2008, MosEnergo (former TGC-3) in 2009 and BiyskEnergo (a small IPP) in 2010.

To summarise, the post-reform electricity market in Russia is likely to suffer from concentration and regional or local market power, as was the case of other post-reform countries. Gradual market liberalisation of 2007-11 in Russia removed regulated contracts without imposing compulsory contracting (e.g. at free prices) hence the incentives to exercise market power were amplified, however the bid-at-cost rule is supposed to mitigate the problem. Further part of this paper discusses various measures of market power, then estimates the concentration level in the Russian electricity industry and test the hypothesis of actual market power abuse.

3. Market power – theoretical measures

Market power is defined as the ability to alter prices profitably away from the competitive level[20]. Study of market power, or indeed any issue of competition, requires definition of the market in terms of product and geography. In case of electricity, the need to constantly balance supply and demand adds time dimension to this definition. Electricity is a standard product, subject to voltage, frequency and other technical requirements. As for geography and time, these must be examined jointly. First, almost any electricity market exports and imports energy, so mere geographical or administrative bounds are not sufficient to define a full set of suppliers and consumers. Second, as demand varies during the day and throughout the year, some transmission lines might be congested and some areas might become isolated (even for a few hours a year). Consequently, a geographical market might expand or "shrink" according to demand fluctuations.

Traditionally, antitrust regulatory authorities have relied on concentration measures to evaluate competition in the industry, for example, the Herfindahl-Hirschman (HHI) index. Specific features of electricity market require more sophisticated measures, of which we will discuss the Residual supply index (RSI), together with the Transmission-constraint RSI, and the Lerner index. We also discuss the role of contracts in mitigating market power.

[20]The definition is standard and can be found, e.g. in Mas-Colell et al. (1995), page 383, or Stoft (2002), page 316.

The Herfindahl-Hirschman index is a concentration measure used by many competition and anti-monopoly authorities to examine the potential for market power in the industry. HHI is computed as the sum of squared percentage shares ($HHI = \sum_j (s_j)^2$ where s_j is the percentage share in total output) and ranges from 0 to 10,000. According to the US Department of Justice, a market with HHI below 1,500 is not concentrated, a market with HHI between 1,500 and 2,500 is moderately concentrated and a market with HHI above 2,500 is highly concentrated[21]. On the electricity markets HHI is usually based on installed capacity (accounting, if necessary for export and import capacity), but for several reasons discussed below it is a poor indicator of market power.

In the electricity industry, market power can be exercised either by physical capacity withholding or by bidding above competitive prices. Any generator in principle may attempt to withhold capacity, whereas a marginal generator (i.e. one that is the last to be used to meet the demand and whose bid determines the equilibrium price) also has incentives to attempt to raise the price. Either behaviour leads to an upward shift in the supply curve and to the distortion of the equilibrium price and output: the price is increased and the output is decreased. [22]

Full information on plants' thermal efficiency and fuel prices would make bidding above marginal cost very unlikely, as such behaviour can be easily detected. Moreover, historical information on outages makes capacity withholding less probable. From a practical perspective, a recently liberalised market typically has a comprehensive data set on plants' efficiency in the public domain, inherited from the pre-reform utility company. As the market develops, information on outages is accrued, e.g. by the Independent System Operator and/or the regulatory authority, who are then able to monitor the generators for market power abuse.

Standard IO models do not distinguish between potential for and actual exercise of market power (e.g. a standard monopoly is assumed to exercise market power by default). [23] In electricity markets this distinction is important, since demand varies during the day and short-run demand is known to be inelastic. [24] There is little significance in exercising market power

[21] U.S. Department of Justice and Federal Trade Commission (2010) "Horizontal Merger Guidelines", § 5.2.
[22] See Stoft (2002), page 320, figure 4-1.1, and the related discussion of quantity withholding, quantity and price distortion
[23] By definition, exercising market power in market is assumed to be always profitable and a rational firm is expected to exercise market power if there is an opportunity to do so (e.g. a monopoly would always raise its price above the competitive level).
[24] See, for example, paper by Borenstein et al. (1999) on the suitability of concentration measures for the competition analysis of the electricity industry.

when the demand is low or, in other words, when there is enough spare capacity. A marginal generator that attempts to withhold capacity or bid above the competitive price is very likely to be replaced on the market by another (idle) producer. By contrast, market power abuse is more probable when demand is peaking (i.e. when there is little spare capacity and demand does not respond much to price changes). In such circumstances the marginal producer might find it profitable to reduce output, perhaps by a small amount, to induce a large price spike and enjoy excessive profits.

Since it is actual production, not installed capacity that matters, HHI based on capacity is a poor indicator of market power (although it can indicate long-run positions of the producers on the market). A relatively small independent producer might be marginal on the market and hence enjoy considerable market power during peak periods. To assess the importance of any supplier should it become marginal, or pivotal, the California's ISO (CAISO) developed the Residual Supply Index. The RSI is computed as follows, for each hour in the year (Sheffrin, 2002):

$$RSI = \frac{\text{Total Supply - Largest Seller's Supply}}{\text{Total Demand}}$$

The RSI screen test states that the index should be more than 110% for more than 95% of the hours is a year. Sheffrin observes the RSI exhibits strong correlation with the Lerner index and thus can serve as a good proxy for actual market power, without the need to estimate production costs, equilibrium prices and mark-ups. Swinand et al (2008) provide a theoretical model based on firm's residual demand that links together firm's individual mark-up, RSI and absolute demand elasticity:[25]

$$\frac{P - MC_i}{P} = \frac{1 - RSI_i}{\varepsilon}.$$

Individual price-cost mark-up is inversely and linearly correlated with RSI. Moreover the intercept and the slope are equal in absolute terms so that the relationship can be easily verified empirically.

The RSI was developed for a single-zone market without major transmission constraints. Lee et al. (2011) pointed out that the index is not suitable for a market which uses locational marginal prices and wherein many lines are congested for a significant number of hours. They

[25] See the Appendix 1.Model 3C for details.

offered a transmission-constrained *RSI* (*TCRSI*) which is computed for each a generation company as R_F using a simple linear programming model:[26]

$$\max_{q,t} R_F \tag{2.3}$$

s.t. $$\sum_k q_i^k + \sum_{k,j} x_{ji}^k = R_s \cdot D_i, \forall k, i \tag{2.4}$$

$$q_i^k + x_{ij}^k \le K_i^k, \forall k, i \tag{2.5}$$

$$\sum_k x_{ij}^k \le T_{ij}, \forall \{ij\} \tag{2.6}$$

$$q_i^s = x_{ij}^s = 0, \forall s \in F \tag{2.7}$$

where R_F – transmission-constrained RSI for firm *F*,

s – index of the generating unit for which TCRSI is computed,

$i \in \{1,...,28\}$ – index for free flow zones,

$k \in \{1,...,139\}$ – index for a generation unit, continuous numbering,

q_i^k – output of unit k located in zone i for in-zone consumers,

x_{ji}^k – output of unit k located in zone i for export to zone j,

D_i – demand in zone i,

K_i^k – installed capacity of unit k located in zone i,

T_{ij} – transmission constraint from zone i to zone j, Note that $T_{ij} \neq -T_{ji}$ as the actual network topology may results in different limits on the aggregate flows from i to j and from j to i.

$s \in F$ – all generation units *s* that belong to firm *F* for which TCRSI is computed,

The TCRSI is estimated for the hour of peak demand only; consequently it is more suitable to evaluate market power in the long run. By contrast, computing the index for all hours in a year would provide insight into short-term power abuse and indicate which congested lines require reinforcement or an increase of their transmission capacity in the first place.

The Lerner index is initially developed for the case of the monopoly (see Appendix 1. Model 3A for a formal model). The index is written as $LI = (P - MC)/P$ where P is the market price and MC is marginal cost. In case of the monopoly the index is inversely proportional to the absolute elasticity of market demand: $LI = 1/\varepsilon$. When the demand is inelastic, the monopoly has stronger incentives to raise the price without losing too many

[26] The model is also replicated in Appendix 1. Model 1.

customers and hence it would gain extra profits. The model is then extended to Cournot oligopoly (Model 3B) to derive firm-specific and industry-average Lerner indices which are also inversely proportional to demand elasticity. In addition, the firm's index is proportional to the firm's share of the market, $LI_i = s_i / \varepsilon$, and the industry index is proportional to the concentration as measured by the Herfindahl-Hirschman index, $\overline{LI} = HHI / \varepsilon$.

As discussed above, when electricity demand is low, generators have little incentive to manipulate capacity; hence observed prices are expected to be close to marginal cost. When demand is high and supply of capacity is tight, prices may increase due to demand-rationing rules (absent price caps on the market) or due to market power abuse. The curve of observed prices would be steeper than the supply curve, and the mark-up curve would be increasing (figure 1, left pane). In an electricity market with must-run generation (that has zero-price bids) the left part of the supply curve is zero, so the mark-up curve would start at one and then return to a normal increasing curve (figure 1, right pane).

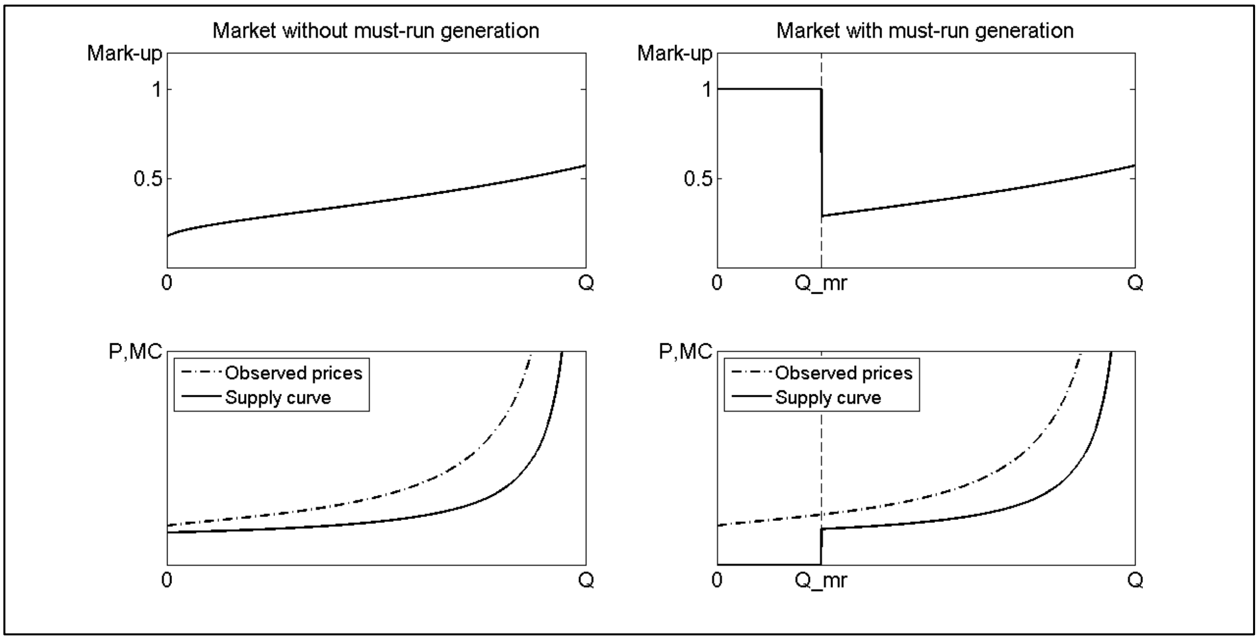

Figure 1. Mark-up dynamics on electricity markets without and with must-run generation.

Examining the Lerner index indicates that there are essentially two ways to reduce market power: by increasing demand elasticity or by reducing individual share in total output. The first option is not feasible in the electricity market, since most consumers, particularly households, do not have an opportunity to respond to real-time prices. The second option might imply stronger competition (e.g. through reallocating more evenly the output among the existing producers or through new entry). Either option is costly because it requires construction of new capacity by fringe or new producers and does not help mitigate market power in the immediate future. However, reducing firm's sales in a *spot* market, through forward contracts, reduces firm's incentive to manipulate the *spot* price. Consequently, forward contracting becomes another way to mitigate market power, without altering the number of competitors or the total demand.

Allaz and Vila (1993) presented a theoretical framework of a duopoly with linear demand, constant marginal cost and forward contracting. They showed that when the number of forward trading periods tends to infinity (or equivalently, when trading becomes more frequent), competitors sell forward in the first period and attempt to contract the residual demand in the future periods (to beat each other) so that the uncontracted demand eventually vanishes to zero. The incentives to increase the spot price above marginal cost disappear, hence the duopoly prices and output tend towards those in perfect competition. Other papers modified the model under consideration, such as the supply-function framework (Green, 1999) or Bertrand competition (Mahenc and Salanie, 2004). Bushnell (2007) extended the model to oligopolies with increasing marginal costs and calibrated the results to several US markets. He concluded that, under certain conditions, forward contracting is equivalent to increasing the number of suppliers from n to n^2, or in other words, to introducing stronger competition

With large volume of forward contracts, the generator has lower incentives to manipulate the spot price as it only affects the uncontracted demand. It can be shown that both the RSI and mark-ups are also smaller. In a situation where a generator is over-contracted (i.e. has to sell more energy under forward contracts than it is willing to produce given its current cost structure), it acts as a buyer on the spot market and is more interested in lower spot prices. Hence, the incentives for manipulating the spot price are reduced greatly, if not removed completely.

In summary, to detect market power abuse in the electricity market, one should use measures based on uncontracted output and cost rather than on installed capacity. Estimating the Residual Supply Index and Lerner Index is preferred, although HHI can be used for analysing long-run perspectives on the market. Since demand is very inelastic in short-run and construction of new power plants and lines requires a long time, forward contracting is an instruments that can be immediately enforced in the market by the regulatory authorities to mitigate market power.

4. *Ownership and concentration in the Russian ESI*

The privatisation of the RAO EES power plants aimed at attracting private investors to the industry. A variety of private shareholder would guarantee, at least *ex ante*, competition between producers. However, the final number of owners turned out to be quite limited. The ownership of the major generation companies in the industry at the end of the unbundling process and three years later is given in table 1.

Despite efforts to privatise the new generation companies, the federal government appeared among the main stakeholders. The state-owned Gazprom and its subsidiaries secured control in four generation companies with total capacity of 36 GW. The private Russian holding IES, Integrated Energy Systems, acquired shares in another four companies (15 GW in total), and the Siberian coal-mining holding SUEK bought TGC-12 and 13 (7 GW in total). Other generation companies each have a separate owner, either a Russian or a foreign investor predominantly from the energy industry. In particular, E.On (Germany) acquired the Fourth WGC and Enel (Italy) bought the Fifth WGC, while Fortum (Finland) became the owner of the territorial company TGC-10.

Not all generation companies found new owners and investors. The first WGC was not sold to anyone and, as a temporary measure, was transferred to the FSK, the national grid company. In other words, the cornerstone principle of the reform, separating transmission from generation, was violated, albeit for a short period. Once an owner, the FSK transferred the voting right, and subsequently sold the shares, to the InterRAO company.

From 2008 to 2011, the situation has changed drastically. After a series of mergers and share acquisitions through Gazprom and the InterRAO company, the federal government reinforced its position as the main stake-holder. InterRAO was initially a small state-owned producer but endowed with a monopoly on cross-border electricity trade. The company had a few power plants near the state borders of total capacity 1.833 GW. As a result of the acquisitions, InterRAO has now significant shares in five generation companies, between 20-40%, so that the amount of capacity under its control in proportion to the shares is around 23 GW. As a result, the two aforementioned companies together control about 42.6 GW or 25% of the installed capacity on the wholesale market. The pre-merger companies had power plants in different zones so that competition within one zone seems unaffected, yet the situation may change when some of the zones are integrated with each other (see below).

In short, Gazprom and particularly InterRAO, being both state-owned companies, are used by the government to undo privatisation. The core idea of the reformed market where producers would compete against each other is put at risk, if not rejected.

A thorough study of concentration in the Russian ESI was done by Pittman (2007). The author estimated the HHI of the six dispatch zones of the country[27] at the start of the reform given the then-proposed ownership of the power plants. The HHI based on the installed capacity in each dispatch zone ranges from 1,318 to 2,460, which indicates moderate concentration. The author then aims to show that concentration measured as a cumulative share of the largest *n* power plants in the area differs from season to season by accounting for seasonal variation in hydropower capacity (the largest capacity is in the spring, the lowest is in the winter) and baseload status of CHP (baseload in the winter and peak in the summer). He argues that in winter concentration is higher and competition is worse as fewer power plants compete for non baseload demand. In spring, the state-owned hydropower plants have larger production capacity and as a results larger market share, which also threatens competition.

Pittman conducted his research when the exact market zoning was not clear yet, so he used the technical dispatch zones (the smallest 'units' available at the time) and, because the dispatch zone are quite large, he did not have to consider import flows. Gore et al. (2012) offered an estimate of the HHI in 2008 given the new market zoning and initial ownership structure, however they did not account for imports either. For example, a company that has power plants in a given zone typically also has plants in the neighbouring zones, and it might manipulate imports in order to influence supply and prices in the given zone. We suggest re-estimating the HHI as of 2011 and including imports in the calculation. Considering all possible company-specific imports would complicate the analysis heavily so and shall treat all inflows to a given zone (a) as one independent supplier, or (b) if the import share is high enough, in pro-rata to the installed capacity of companies from the export zones. More precisely, the import is the maximum of total hourly inflows during the year 2011. The results are presented below in figure 2 and the detailed calculation can be found in Appendix 2, Table 2.

[27]The total number of the dispatch zones is seven; the Far East zone was not considered in the study.

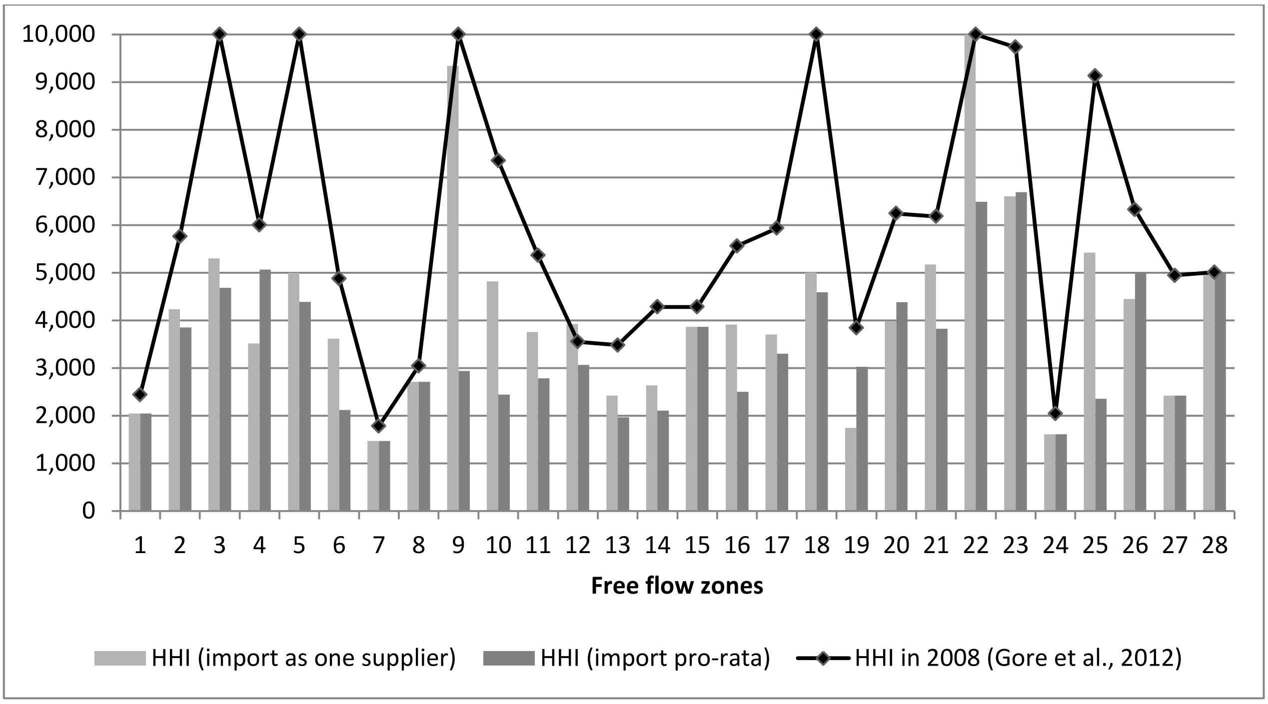

Figure 2. HHI for free flow zones, import as one supplier and import pro-rata.

Our calculations show that prior to the merger wave none of the free flow zones have HHI sufficiently below 1,500, that is all zones are moderately or highly concentrated. Two lowest HHI values are 1,466 in zone 7 'Ural' and 1,606 in zone 24 'Centre'. Four other zones have HHI between 2,000-2,500. These zones are either big in size and/or with relatively mild transmission constraints. The median HHI value is 3,915 and the weighted index is 2,763.Many small zones have at most one TGC, maybe supplemented by one or two power plants of some WGC, and quite strong transmission constraints, so they are highly concentrated.

Correcting for the mergers, the HHI index does not change dramatically. The main reason as mentioned above is that the pre-merger companies generally operated in different free flow zones. Yet, after the zone integration the issue of imports and cross-zone market power might become more sensitive.

Accounting for imports in proportion to installed capacity of the companies from export zones indicates that the concentration might be not so severe. The two zones with HHI above 9,000 have the index dropped to 6,487 (zone #22) and even to 2,937 (zone # 9). Many other zones also have lower HHI by 400…1,500 points (as compared to the one-supplier case).

While the study by Pittman and our HHI estimates highlight the importance of zoning and transmission constraints, evaluating the TCRSI for each station provides further insight into the problem. Stations with TCRSI below one (i.e. those indispensable for meeting local demand) are typically located in smaller zones with weak transmission links to the rest of the market. The installed capacity of the station might be relatively small (e.g. as little as 100 MW) but given the small size of the zone and limited potential for imports, withdrawing such a station from the market (for example as the result of an outage) may lead to load shedding. Any generation company that has plants in such small zones can potentially exercise market power, by declaring the whole plant, or some generation blocks, unavailable.

There are three clusters of smaller FFZs that appear particularly sensitive to plant outages. The first cluster is located in the south of Siberia, the second cluster is in the Ural region and the third one is in the south of Russia (the latter two are in the 'Europe' price area). Each of the zones has between one and three stations, typically thermal power plants and a CHP, sometimes combined with a medium-sized hydropower plant.

Estimating zone-based HHI and transmission-constrained RSI indicates the need to unlock small free-flow zones in order to improve efficiency. Construction of new lines and modernisation of network equipment is already a major part of the FSK investment programme. The results are promising: from 2013 the System Operator will integrate four smaller zones into their respective larger neighbours, and from 2014 there will be further integrations of two other small zones, so that the total number of FFZs will be reduced from 28 to 22.Some of the integration will take place in the south of Russia and will clearly improve competition in that area.

To summarize, the unbundling of RAO EES's monopoly and privatisation of new generation companies offered an opportunity to create a pool of competitive owners and ensure competition on the market. Subsequent mergers and acquisitions created a moderately concentrated industry, where the federal government has the largest stake. Further consolidation of the assets would most probably be detrimental to competition. In addition, market zoning complicates the situation, but the network reinforcement currently implemented by the Federal Grid Company should alleviate the situation in the near future.

5. Mark-up dynamics

Having examined long-term prospects for market power, we shall now discuss short-term dynamics, in the context of market liberalisation. We will first describe the pricing rules and the role of contracts in the Russian electricity industry during and after the reform, then present a model to evaluate price-cost mark-ups and assess their dynamics over the course of liberalisation. Our main finding is that mark-ups have reduced as a result of removing tariffs- this is quite surprising given that one would normally expect an increase. However, examining the mark-up dynamics before and after the liberalisation produces more consistent results.

5.1. Liberalisation and types of contracts

As part of the reform, the wholesale market for electricity and capacity was completely re-designed. The final aim was to replace tariff regulation (which proved to be inefficient) with free pricing and contracts that would ensure efficient production and consumption (i.e. production by the lowest cost generators and consumption by customer with the highest price bid).

Given the size of the industry and the novelty of the trading approach, tariff regulation was not removed "overnight" but rather reduced gradually over time. The approach is not unique: other countries (e.g. England & Wales) used vesting contracts to ensure smooth transition from the regulated industry to the free market. In Russia, since January 2007 the volumes of electricity sold under the tariff have decreased by 10-15 percentage points every six months. Consequently, the volume of electricity in the free sector of the market was constantly increasing. Since January 2011 the wholesale market is fully liberalised. As for the retail market, small commercial customers received an opportunity to freely choose their suppliers, whereas households still buy their energy at the regulated prices from the supplier appointed by the regional authority.

Figure 3 depicts the actual shares of the regulated sector (measured as the ratio of volume sold under tariffs to the total volume traded) versus the liberalisation schedule. It is interesting to observe that the actual share of regulated contracts was in line with the scheduled level in the early stages and somewhat above the scheduled level in the later stages. A possible (although certainly not the sole) reason for such discrepancy could have been the financial crisis that hit the economy in late 2008. The share of the regulated contracts was measured with respect to the 2007 production volume, and the respective amount of regulatory sales was fixed for the whole period of liberalisation. When the total demand decreased in 2009-10, the share of regulated volume (fixed at the 2007 level) increased naturally.

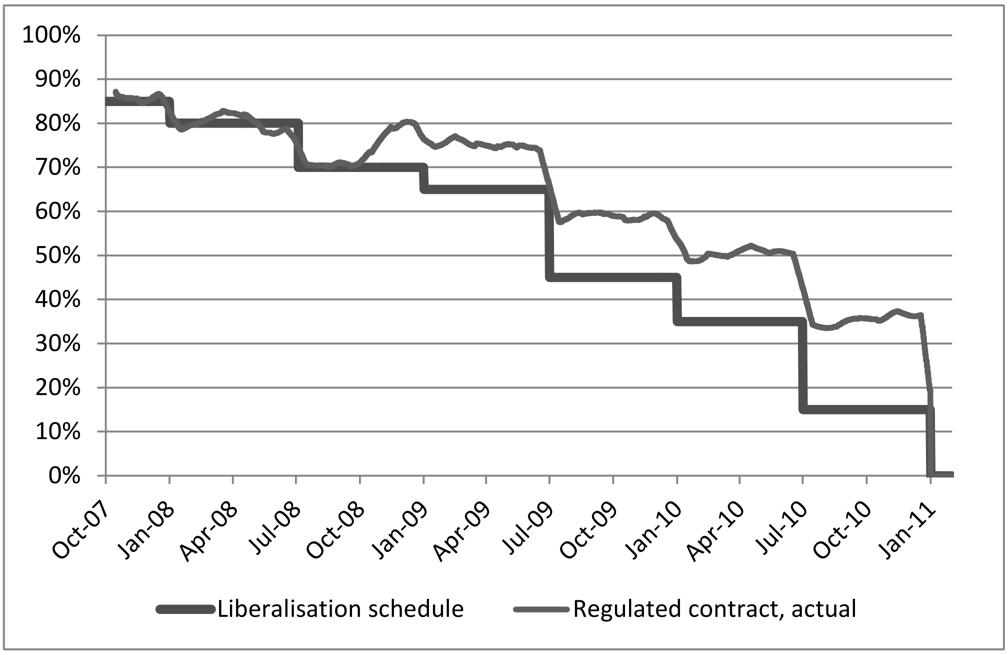

Figure 3. Liberalisation of the Russian electricity market: schedule and actual pace.

Once the market was liberalised, regulated tariffs and contracts did not disappear from the market. Russian households still buy electricity at fixed retail prices from appointed suppliers, who, in turn, buy electricity on the wholesale market under regulated wholesale tariffs only. The practice is imposed by the government in order to eliminate price risk for the appointed suppliers. The share of such contracts in 2011 fluctuated around 15%, corresponding to a share of household consumption of 12% (cf. 26% in the EU-27).[28] The rest of the wholesale electricity market, including purchases for non-household retail supply, is fully liberalised.

The free sector of the market consists of free contracts and a centralised power exchange. During the transition period the market had contracts for electricity and capacity, as well as contracts for electricity only. The joint contract was a popular tool to secure supply in peak hours, albeit the gross volume contracted was not very significant. In a peak hour, the contracted volume could reach 26% of the total amount traded, while the annual share of such contracts was a mere 5%.[29] With the liberalisation of the capacity market and the introduction of long term capacity auctions, joint contracts are no longer in use. Only pure electricity contracts remain on the market, but they are not widespread either: a share of the contracted volume never exceeds 10% in any one hour. Nonetheless, the annual share of such contracts is also 5% which indicates more even use throughout the year.

[28] Source of figures: share of contracts 15% - author's estimate based on data from the Commercial Operator; household share in consumption in Russia 12% - Russian Statistics Service; household share in consumption in EU 26% - OECD.
[29] All figures in this paragraph are author's estimates based on hourly data from the Commercial Operator.

The regulated contracts used in the Russian electricity market by nature represent the vesting contracts used in other countries to ensure smooth transition from the regulated industry to a free market (e.g. in England and Wales). The vesting contracts facilitate the transition but since they expire without a requirement for renewal, they help mitigate market power only in the short-term. Free contracts do not appear popular on the Russian market, so the issue of market power remains unsettled.

5.2. Estimating benchmark prices and the Lerner index

To evaluate the role of contracts in market power, we first need to estimate the Lerner index, which is a conventional instrument to estimate price-cost mark-up on the electricity market. The index is computed as $LI = (P - MC) / P$ and is evaluated in empirical studies as $LI = (P^{actual} - MC^{estimate}) / P^{actual}$.

Given that MC is unobservable, we estimate the unit production cost of the marginal plant, and hence the equilibrium price, using the linear programming model. In the model, the objective function minimise total cost of meeting demand in each hour given installed capacity and transmission constraints (full details can be found in the Appendix 1.Model 2).

Our estimate considers only fuel cost, so an index below 20% is not very informative. Rather, it is relative changes in the Lerner index (in particular, spikes or shifts in the trend) that would indicate the exercise of market power.

The model generates equilibrium, or benchmark, prices for all 28 zones. Figure 4 presents the Lerner index for the three largest FFZs no. 1, 7 and 24 over two years (smoothed by MA 28-days filter).The time series appear to be stable, with humps in the summer periods. The model estimates the price to be very low during the summer due to small demand, but the actual price appears somewhat higher (perhaps due to technical requirements), so the Lerner index looks excessive. The summary statistics are given in Appendix 2, Table 2.

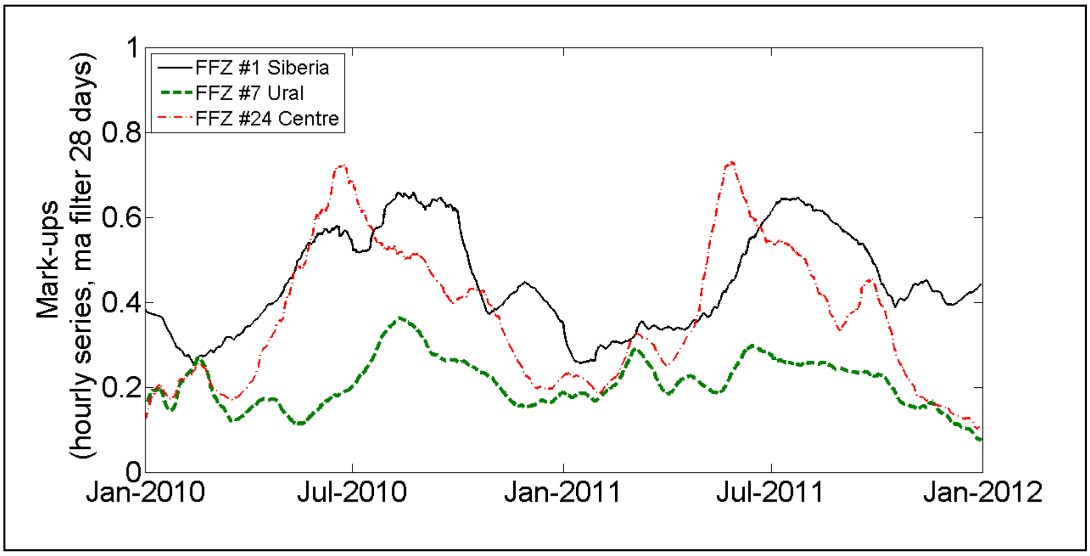

Figure 4. Mark-ups (MA 28 days), free flow zones 1 'Siberia', 7 'Ural' and 24 'Moscow'.

Fitting the trend to individual LIs produces statistically significant estimates for the time coefficient and the intercept for the bulk of the zones (see table 3). Hence, we use ADF testing with trends and intercepts to examine the stationarity of the Lerner index (ADF test with intercept only for zones without a significant trend slope).All zones have a stationary LI within the full sample in each year and half-year[30].

We then compare the dynamics of the Lerner index during the two respective years and half-years. To this end, we define the first difference as $\Delta LI = LI_{2010} - LI_{2011}$and test for the presence of a trend and stationarity. The first difference has zero mean value and appears to be stationary both within the year and the two half-years.

Comparing dynamics of LI helps clarify the overall trend but it tells little about the growth of LI in relation to the demand growth. In order to compare LI before and after the liberalisation at the same level of demand, we plot consumption versus LI for 2010 and 2011. LI at the highest levels of demand is of particular interest when the potential for, or the temptation of, abusing market power is the strongest.

When plotting LI versus consumption, the series are sorted by volume of consumption, from the lowest to the highest value. Visual inspection of the graphs for each zone gives two types of patterns of LI dynamics. Graphically, the two patterns are illustrated on figure 5. The horizontal axis is electricity demand (sorted from lowest to highest); the vertical axis is the corresponding value of the Lerner index (mark-up) on the top panel and the fuel cost. Theoretically, the two patterns are associated with different types of supply curve, with and

[30] For test statistics see the Appendix 2. Table 5.

without must-run generation which translate into different mark-up dynamics (cf. figure 1 in section 3).

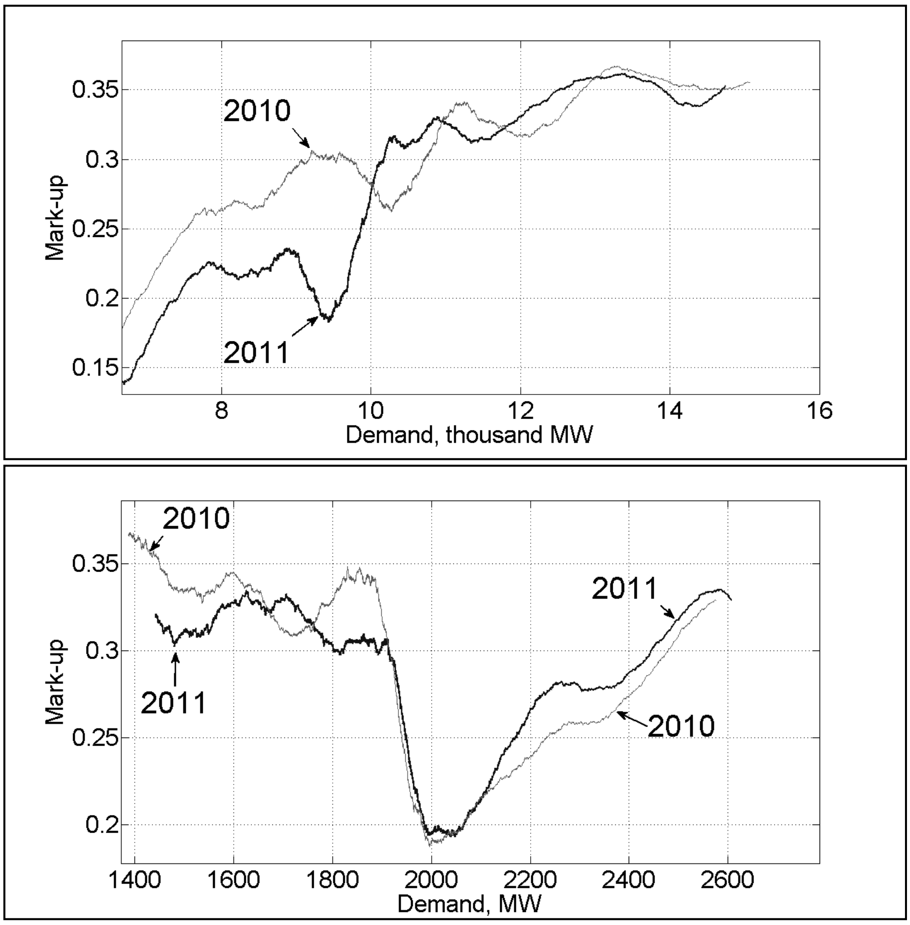

Figure 5. Demand versus mark-up, two patterns. Zones 26 'Moscow' (top) and 12 'Vyatka' (bottom).

Note. The two zones are chosen for illustration only; all other zones have one of the two patterns.

One pattern is associated with zones that have no low-cost generation. In these zones the equilibrium price is positive in (almost) any hour and is increasing with the level of demand. Hence, LI starts from a small value (perhaps from zero) and grows monotonically as the demand is approaching the overall capacity limit.

The other pattern is associated with zones dominated by hydropower or nuclear generation. Typically such generation is treated as must run and operates under price-taking bids. In such zones the estimated equilibrium price is almost zero at a low level of demand. The price becomes positive at a high level of demand when the hydropower stations reach their capacity limit and thermal stations come into operation. Consequently, the LI is extremely high when demand is small and reflects the price-cost margin when demand is approaching the capacity limit.

The bulk of zones exhibit the first type of pattern (twenty zones in total).The zones with hydropower generation that exhibit the second type of pattern are zones # 1 (in Siberia), zones # 13-17 (along the river Volga) and #27-28 (St. Petersburg and northern areas with clusters of small hydropower stations). In zone #27 the pattern of LI is driven by the presence of both hydro- and nuclear power plants.

Graphical representation might indicate that LI is relatively high at the peak level of demand, yet our model considers fuel cost only, not operation and maintenance expenditure. Assuming the latter account for 30% of the total variable cost, LI appears to fluctuate around zero for most zones. Comparing the consumption-LI graphs for 2010 and 2011 shows that hourly mark-ups did not change significantly as the market was liberalised. For the majority of zones, LI does not increase for the same level of demand: the change is within 5 percentage points. Thus, we conclude that although HHI and RSI measures indicate the potential for market power abuse, hourly LI estimates do not support the hypothesis of actual market power abuse.

5.3. Lerner index - Tobit regression

Regulated tariffs can be interpreted as contract sales, wherein both the volume and the price are known well in advance. Since the tariffs are below production costs, generators are expected to bid above competitive prices in order to receive positive profits. Removing regulation reduces the incentive for upward bidding; hence the mark-up is expected to decline over time. It is therefore useful to test the level of market power (as measured by the price-cost mark-up) against contract volumes, for both regulated and free contracts, while compensating for other variables (seasonality, weather, etc.).

Since the variable of interest, in the Lerner index, is limited at least from above, we will use the Tobit (or censored data)models. We also bound the index from below (at -1) to exclude the outliers which represent less than 1% of the sample.[31] The estimated equation and the summary statistics for the continuous variables are presented below (the full list of variables and data sources are given in Appendix 2, Table 4).

$$LI = \begin{cases} -1, & LI^* \le -1 \\ LI^*, & -1 < LI^* \le 1 \end{cases} \tag{2.8}$$

[31] Strictly speaking, the Lerner index in our model has a corner solution at 1 and is censored from below at (-1). The model set-up, however, remains the same. See Wooldridge (2002, p. 517-520).

$$LI^*_{i,t} = \beta_0 + \beta_1(share\_of\_regulated\_contracts)_{i,t} + \beta_2(share\_of\_free\_contracts)_{i,t}$$
$$+\beta_3(shoulder\_hour)_t + \beta_4(peak\_hour)_t + \beta_5(season\_winter)_t$$
$$+\beta_6(air\_temp)_{i,t} + \beta_7((air\_temp)_{i,t})^2 + \sum_i \alpha_i FFZ_i + \varepsilon_{i,t} \qquad (2.9)$$

Table 1.Summary statistics for the continuous variables.

Variable	Mean	Std. Dev.	Min	Max
Lerner index	0.34	0.40	−1	1
Share of regulated contracts, %	31.0	19.45	0	67.49
Share of free contracts, %	8.40	7.33	0	36.27
Air temperature, degrees °C	4.55	14.31	−44.8	40.90

As can be seen from the equation, we use air temperature and the seasonal dummy as proxies for energy demand rather than heating/cooling degree days. The main reason is the position of CHP power plants in the Russian electricity system which account for half of thermal generation and third of the system. CHP plants supply heat centrally to many cities and municipalities because households live predominantly in blocks of flats and do not have individual boilers. Hence using the variable ‘heating/cooling degree days’ probably does not make much sense.

The seasonal dummy is used not to reflect the winter period per se but to reflect different status of CHP plants in winter and summer. During winter CHP plants operate in heat mode which is equivalent to base load status. During summer CHP plants operate as pure thermal stations and can have flexible load. The change of CHP status affects significantly the amount of baseload, or must run, generation and the amount of residual supply, and hence the equilibrium prices.

As a part of sensitivity analysis, we estimate a regression with the interacted variables “air temperature” and “winter season”. The results show that the coefficient of the share of free contracts change but the marginal effect on reducing market power is still small. However, the key coefficient of interest, on the regulated contracts, remains unaffected so is the main conclusion on the impact of de-regulation on market power.

There are two potential problems with the Tobit specification outlined above: construction of the dependent variable, and autocorrelation in residuals.

The use of a constructed dependent variable, such as the Lerner index, requires extra care, since it is not observed, but rather constructed from real electricity prices and benchmark prices (which, in turn, are equal to estimated marginal cost). While real prices might be treated as a realisation of a random variable, benchmark values are derived from a linear programming model and are therefore non-random. Running the model several times with different input data (e.g. fuel prices or plant availability) could generate multiple price samples and hence a probability distribution. However, Russian fuel markets rely heavily on long-term contracts with fixed prices, and the data on outages is not publicly available, so the results of the Tobit regression cannot be tested against the non-randomness of the Lerner index.

Potential autocorrelation of the time series or residuals might affect the estimates. First, the disturbance term might be an AR(p) process; second, the latent variable might depend on its lagged value in the previous hour; and finally, some variables could be omitted from the analysis. The AR process reflects the fact that an exogenous shock is persistent over several periods (e.g. when a failed transmission line requires time to be repaired, during which a generator could otherwise exercise market power). A lagged dependent variable would imply that a generator bids upward for several hours, because an isolated high bid in any one hour would certainly attract attention. As for omitted variable problems, the most significant is probably the reserve margin, which might be difficult to compute for a sub-zone of the market. The short-run horizon and the inclusion of hour-type dummies should tackle the problem, to a certain extent.

Bearing this in mind, we still find it useful to run the most simplified Tobit regression in order to gain some insight into the liberalisation and market power.

Our sample contains 28 free flow zones, or units, and 17,520 hours (8760 hours/year multiplied by2years) so it is panel data. The total number of observations is 490,532 of which a mere 688 are censored at (-1) and almost one fifth (105,838) is a corner value (at +1). The appropriate Tobit model for our panel would consider fixed effects. However, we can still use a Tobit model for cross-section data with unit dummies, since the number of units is fixed and the time horizon is quite large, thus estimates should be both consistent and efficient[32].

[32] Typically, censored panel data comes from household surveys (i.e. with a large, and increasing, number of units and few annual observations per unit). Using a Tobit cross-section model is not appropriate in this case, as the estimates are inconsistent with $N \rightarrow \infty$ and T fixed (the so-called incidental parameters problem; see Neyman and Scott, 1948). Honore (1992) and Alan et al. (2011) developed a non-parametric estimator for use with household surveys. Our model is fundamentally different because we have a fixed number of units and an expanding horizon, N fixed and $T \rightarrow \infty$. In such a case, a Tobit cross-section model with unit dummies would produce both consistent and efficient estimates and the use of a special Tobit-panel model is not necessary; see also Greene (2004).

Baseline results for the Tobit regression are given in table 5. Three specifications are considered: (i) without the FFZ dummies, (ii) with FFZ dummies and (iii) with FFZ dummies and the interaction of hour-type and season variables. The third specification provides a more refined response for the latent variable with a combination of hour-type and season, while the coefficients of other variables are roughly equal to those in the second specification. The discussion below is based on the third model.

All coefficients appear to be statistically significant and the conventional variables all have the correct sign. The temperature coefficients would suggest that a high temperature is more likely to aggravate market power, as opposed to extreme values below zero. Heat in the summer appears more problematic, despite low demand in general, since many generators have scheduled maintenance during this period, hence the available amount of capacity to support air conditioning is limited. As for low temperatures, the effect is partially captured by the winter dummy variable.

Since the regression is nonlinear, using the coefficient values for quantifying the impact on the dependent variable is not correct; instead, one must use the marginal effects (see the Appendix 1. Model 4 for the relevant formula). Computing the marginal effect for the hour dummies shows that shoulder and peak hours add 9-10 percentage points (p.p.) to the Lerner index. Furthermore, winter adds another10-13 percentage points (p.p.) to the index in any hour (off-peak, shoulder or peak). Altogether, this implies significant variation in market power between summer off-peak and winter peak hours.

The key variable of interest, the share of regulated contracts, has a positive coefficient which implies that liberalisation (i.e. reduction of the share) has decreased potential for market power abuse. In the first half of 2010, the share of regulated contracts was 40% and in the second half of the year it was 20%. The marginal effect of the regulated contract is equal to 0.0352; that is to say that reducing the share of regulated contracts from 40% to zero ***d***ecreased the Lerner index by 1.66 p.p. (0.0415 x 40). The marginal effect of free contracts is equal to -0.0279, so that increasing the contract volumes by 10 p.p. would reduce market power by only 0.2 p.p.

Both types of contracts have relatively small marginal effects, but they are statistically significant. From the competition perspective, this implies that contracting has limited potential for reducing market power in the Russian electricity industry. More emphasis should be placed on other factors, such as reducing concentration or alleviating transmission constraints.

As for the FFZ dummies, only a few of them have positive coefficients; that is to say that they are more likely to suffer from market power abuse compared to base zone 24 ‘Centre’ (a large free-flow zone located in the European part of Russia). These are zones ## 1, 11, 13, 14 and 27.Their marginal effect varies from 7 to 22 p.p. As discussed earlier, the Federal Grid company enhances the transmission network, and some of these zones - namely 11, 13 and 14 (which have the highest marginal effects) - will soon be integrated within their larger neighbours.

Note that the share of regulated contracts has a negative coefficient which at first glance appears at odds with forward contracting models. Running the regression separately for 2010 and 2011 indicates that regulated contracts are probably not very different from free contracts. In the regression for 2010, both types of contract have negative coefficients which conform to the main result of the forward market model (i.e. that contracting reduces market power). Moreover, the contracts now have a much larger effect on the Lerner index. When the share of the regulated contracts dropped from 40% to zero, the index jumped up by 26.5p.p. As for free contracts, increasing their share by 10 p.p. would reduce the Lerner index by nearly 9 p.p.

By contrast, in 2011 the coefficients of the regulated contract, which are now used only to supply households, swap from negative to positive. The marginal effect for regulated contracts equals 0.16; removing household tariffs and any associated regulated contracts (15% of market volume) would thus decrease the Lerner index by 2.4 p.p. Free contracts have less impact on the Lerner index in the liberalised market: increasing their share by 10 p.p. reduces the index by 6.5 p.p.

The results for 2011 suggest that the overall impact of regulated contracts on market power might be related to government intervention in household prices. Removal of regulated contracts would probably have a modest impact on market power, although it might induce more active contracting or even the introduction of compulsory contracts at free prices.

6. Conclusion

The Russian electricity supply industry has undergone major transformation in the last decade, from a vertically integrated monopoly to a competitive market. The history of the market has been reviewed in a few papers but the outcome of the reform has hardly been examined. In this paper we focused on market power, because it proves to be one of the most acute problems in competitive electricity markets.

Our finding is twofold. On one hand, we observe increasing concentration in assets and ownership, counterbalanced by grid development and unlocking of smaller market zones. From a policy perspective, the government should analyse more carefully new mergers and acquisitions, in particular to avoid increase in concentration. The government should clearly continue network enhancement and zone integration in order to support competition in the market.

On the other hand, we estimate price-cost mark-ups and find no sign of significant market power abuse. As a special part of our study, we also evaluate the role of contracting on the wholesale market. We find that the market power index responds in a normal way to contracting, yet the regulated contracts for households seem to bias the picture, and more generally they are likely to affect market functioning. As such, our result presents further, perhaps indirect, evidence of the perverse impact of regulated pricing. Although politically difficult, the Russian government should nonetheless seek to remove tariffs from the market.

We attribute the perceived discrepancy between high concentration and low contracting on one side and low mark-ups on the other side to the cost-bidding rule. The requirement to offer electricity at production cost appears to be a particular feature of the Russian electricity market, a similar rule is found only on the Irish market. The rule ensures that a generator recovers the variable cost on the electricity market, while fixed cost is recovered on the capacity market.

A striking difference of the Russian bid-at-cost rule is that the rule is implemented twice: first, during the weekly unit commitment (UC) procedure, and second, on the day-ahead (DA) market. If a producer submits an extremely high UC bid, he risks being out of the market for a whole week. If he submits a moderate UC bid, he can participate in the DA market but the DA bids cannot exceed the UC figures (thus the UC bid acts as a self-cap on the spot market).

Most importantly, the rule is not only announced, it is also enforced. The Federal Anti-Monopoly Service has already imposed fines on companies suspected of over-bidding. Notable cases include MosEnergo company (former TGC-3) that operates in the Moscow area and TGC-11 that operates in Omsk region among others. Enforcing the cost-bidding rule appears as a sensible and feasible tool to control actual market power abuse and can be recommended for use at other electricity markets or jurisdictions.

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Appendix 1. Models and input data

Model 1. Transmission-Constrained Residual Supply Index

$$\max_{q,t} R_F \quad (2.10)$$

s.t.

$$\sum_k q_i^k + \sum_{k,j} x_{ji}^k = R_s \cdot D_i, \forall k, i \quad (2.11)$$

$$q_i^k + x_{ij}^k \le K_i^k, \forall k, i \quad (2.12)$$

$$\sum_k x_{ij}^k \le T_{ij}, \forall \{ij\} \quad (2.13)$$

$$q_i^s = x_{ij}^s = 0, \forall s \in F \quad (2.14)$$

where R_F – transmission-constrained RSI for firm *F*,

$i \in \{1, ..., 28\}$ – index for free flow zones,

$k \in \{1, ..., 139\}$ – index for a generation unit, continuous numbering,

q_i^k – output of unit k located in zone i for in-zone consumers,

x_{ji}^k – output of unit k located in zone i for export to zone j,

D_i – demand in zone i,

K_i^k – installed capacity of unit k located in zone i,

T_{ij} – transmission constraint from zone i to zone j, Note that $T_{ij} \neq -T_{ji}$ as the actual network topology may results in different limits on the aggregate flows from i to j and from j to i.

$s \in F$ – all generating units *s* that belong to firm *F* for which TCRSI is computed,

Model 2. Estimating benchmark prices

$$\min_{q,x} \sum_{k,i,j} (q_i^k c_i^k + x_{ij}^k c_i^k) \qquad (2.15)$$

s.t. $$\sum_k q_i^k + \sum_{k,j} x_{ji}^k = D_i, \forall i \qquad (2.16)$$

$$q_i^k + x_{ij}^k \le K_i^k, \forall k, i \qquad (2.17)$$

$$\sum_k x_{ij}^k \le T_{ij}, \forall \{ij\} \qquad (2.18)$$

where c_i^k – variable (marginal) production cost of unit k located in zone i,

and the rest of the notation is the same as in model 1.

The objective function (2.15) minimise total cost of meeting demand (2.16) given installed capacity (2.17) and transmission constraints (2.18). The model is solved simultaneously for all free flow zones, for each hour (there is no inter-hour adjustment).

Benchmark, or equilibrium, prices are formally the Lagrange multipliers to the demand constraint (2.2). These are used as $MC^{estimate}$ in calculation of the Lerner index.

The model has 28 zones and nearly 80 lines, with many loop flows, in particular in the European part of Russia. A standard DC loop flow model would be computationally heavy, so we use an approximation where transmission capacity is allocated according to financial transactions, not physical flows. In other words, our model allows only flows between neighbouring zones, i.e. energy can go from zone A to zone B which are connected, but not from A to C (which are not connected) via B, their common neighbour.

A similar model of allocating transmission capacity is used, for example, by the Central Allocation Office that manages cross-border electricity trade between the Central European countries. Their model ignores domestic production and the loop flows that are associated with production and cross-border trade. Another example is Nordpool, commercial operator of electricity trade in the Nordic countries that computes a uniform price and manages congestion between zones given contractual flows (purchase and sale) and not physical flows.

The cost of production in the study is limited to fuel cost only (which represent roughly 60-70% of the total cost depending on the producer). Although including total cost would affect the merit (dispatch) order of the power plants on the market, current market zoning suggest that considering fuel cost only would have little impact on the model outcome.

Companies' annual reports provide data on thermal efficiency (fuel used per 1 kWh(e) produced).The prices of gas and coal are estimated as follows. The coal market is oligopolistic, with sales mainly under privately negotiated contracts. Some generation companies report the contract price and these prices are used as a proxy for companies where direct reports are not available. As gas prices are completely regulated, the current tariffs are publicly available from the regulator's website.

The Administrator of the Trade System publishes various data on market parameters of which we use data on consumption and transmission flows.

The model does not consider start-up cost, planned or unplanned outages, restrictions on must-run generation or inter-hour adjustment by hydropower stations. It does not include the cross-border exports/imports between Russia and the neighbouring countries (which are negligible anyway). The main reason is the absence of data on these parameters.

Sensitivity analysis of the model to sample outage rates, namely 90% availability in the winter and 80% in the summer, shows that prices change in FFZs with dominant thermal capacity or strong congestion. Figure 6 presents the impact of the outage rate on the Lerner index. The top panel corresponds to FFZ 10 which is a small zone with capacity deficit and strong congestion and where the change in LI due to outages is quite strong. Other zones with similar pattern are zones 4, 16 and 17. The correlation between no-outage prices and prices that account for outages in such zones can be 0.67. The bottom panel corresponds to FFZ 24 which is a large zone in the European part of Russia with some spare capacity and where LI remains practically the same. The rest of the zones have the second type of pattern (either because they have spare capacity or mild transmission constraints). Since the exact parameters of outages are not known, obtaining the estimates may present a separate topic for research.

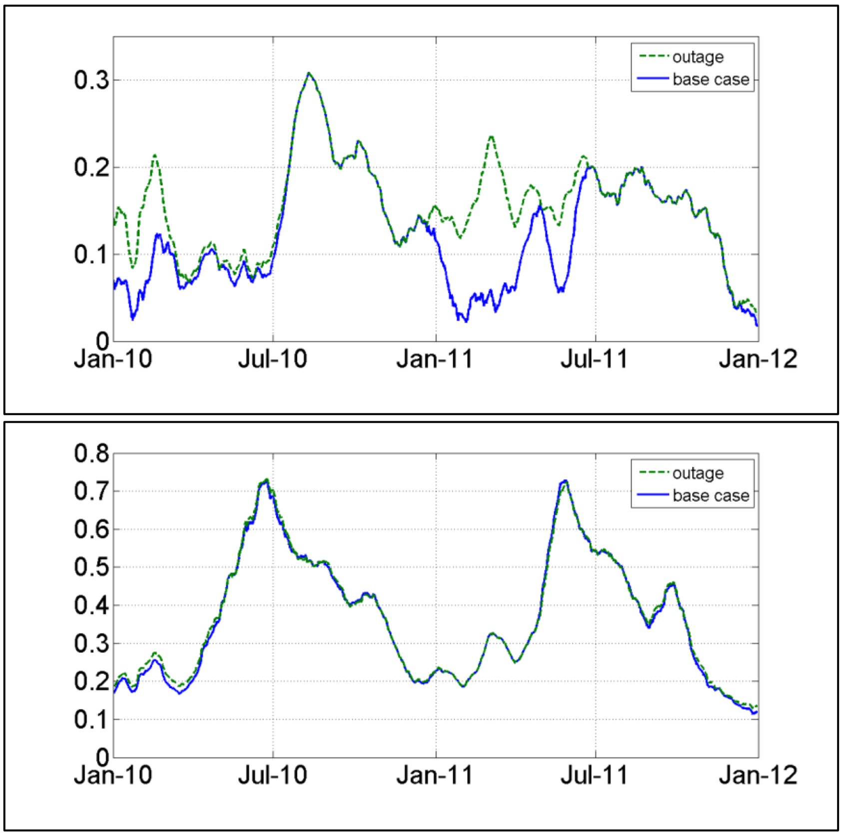

Figure 6. The impact of outages on Lerner index. Zone 10 ‘Serovo-Bogoslovskaya’ (top) and zone 24 ‘Centre’ (bottom).

Model 3A. Lerner index - Case of monopoly

Inverse demand function: $P = P(Q)$ such that $\partial P / \partial Q < 0$.

Production cost is $TC(q)$ and marginal cost is $MC(q) = \partial TC / \partial q$

Profit function: $\Pi(Q) = P(Q)Q - TC(Q)$

First order condition (F.O.C.): $\dfrac{\partial \Pi}{\partial Q} = \dfrac{\partial P}{\partial Q} Q + P - MC = 0$

Re-arranging the F.O.C. as $P - MC = \dfrac{1}{-\dfrac{\partial Q}{\partial P}\dfrac{1}{Q}}$ and dividing both parts by price P yields: $\dfrac{P - MC}{P} = \dfrac{1}{-\dfrac{\partial Q}{\partial P}\dfrac{P}{Q}}$. Realising that (absolute) elasticity of demand is $\varepsilon = -\dfrac{\partial Q}{\partial P}\dfrac{P}{Q}$, we have the formula for the Lerner index: $LI = \dfrac{P - MC}{P} = \dfrac{1}{\varepsilon}$.

Hence, monopoly level of market power is inversely proportional to the elasticity of demand.

Model 3B. Lerner index - Case of oligopoly

Number of firms is N.

Each firm has its own production cost $TC_i(q_i)$ and marginal cost $MC_i(q_i) = \partial TC_i / \partial q_i$.

Inverse demand function: $P = P(Q)$ where $Q = \sum_i q_i$ and $\partial P / \partial Q < 0$.

Firm profit function: $\Pi_i(q_i) = P(Q)q_i - TC_i(q_i)$.

First order condition (F.O.C.): $\dfrac{\partial \Pi_i}{\partial q_i} = \dfrac{\partial P}{\partial Q} q_i + P(Q) - MC_i(q_i) = 0$

Re-arranging the F.O.C. as $P - MC_i = \dfrac{q_i}{-\dfrac{\partial Q}{\partial P}}$,and dividing both parts by price P and also the right-hand side by total output Q yields: $\dfrac{P - MC_i}{P} = \dfrac{q_i / Q}{-\dfrac{\partial Q}{\partial P}\dfrac{P}{Q}}$.

Elasticity of demand is $\varepsilon = -\dfrac{\partial Q}{\partial P}\dfrac{P}{Q}$, firm's share in total output is $s_i = \dfrac{q_i}{Q}$, so firm's specific Lerner index is $LI_i = \dfrac{P - MC_i}{P} = \dfrac{s_i}{\varepsilon}$. Firm's level of market power as measured by the Lerner index is directly proportional to firm's share on the market.

Industry Lerner index is the weighted average of specific indices: $LI = \sum_i s_i LI_i = \dfrac{P - \sum_i s_i MC_i}{P} = \dfrac{P - \overline{MC}}{P}$, where $\overline{MC}$ is the industry weighted average marginal cost.

Alternatively, $LI = \sum_i s_i LI_i = \dfrac{\sum_i (s_i)^2}{\varepsilon} = \dfrac{HHI}{\varepsilon}$, where $HHI = \sum_i (s_i)^2$ is the Herfindahl-Hirschman index, so the industry Lerner index is directly proportional to industry concentration as measured by the HHI index.

Model 3C. Lerner index and Residual supply index.

Note: The model is by Swinand et al (2008), pp. 6-8.

The largest firm maximises its profit facing residual demand which is defined using the efficient rationing rule (Tirole, 1987, p. 213).

Firm's profit function: $\Pi_1 = [D(p_1) - \bar{q}]p_1 - [D(p_1) - \bar{q}]c_1$.

Efficiently rationed demand: $D_1 = \begin{cases} D(p_1) - \bar{q} \ if \ D(p_1) > \bar{q} \\ 0 \quad otherwise \end{cases}$.

Residual supply index for the firm: $RSI_1 = \dfrac{\bar{q}}{D(p_1)}$

Where $D(.)$ – total demand, p – price, $\bar{q}$ – total available capacity of all other firms.

First order condition (F.O.C.): $\dfrac{\partial \Pi_1}{\partial p_1} = \dfrac{\partial D}{\partial p_1} p_1 + [D(p_1) - \bar{q}] - \dfrac{\partial D}{\partial p_1} c_1 = 0$

Re-arranging the F.O.C: $p_1 - c_1 = \dfrac{[D(p_1) - \bar{q}]}{-\dfrac{\partial D}{\partial p_1}}$, dividing both parts by p_1 and the right-hand side by we obtain: $\dfrac{p_1 - c_1}{p_1} = \dfrac{[D(p_1) - \bar{q}]/D(p_1)}{-\dfrac{\partial D}{\partial p_1}\dfrac{p_1}{D}}$.

Substituting for the RSI_1 and elasticity of demand, and dropping the subscript, we have:

$$\frac{P - MC}{P} = \frac{1}{\varepsilon} - \frac{1}{\varepsilon} RSI \ .$$

Model 4. Tobit regression and derivation of the marginal effects

A Tobit, or censored-value, regression was first offered by Tobin (1958). In the exposition of the model we shall follow Amemiya (1984). The model is postulated as follows:

$$y_i = \begin{cases} y_i^*, \text{if } y_i^* \geq y_0 \\ y_0, \text{if } y_i^* < y_0 \end{cases}, \quad y_i^* = x_i\beta + \varepsilon_i, \quad i = 1, \dots, n \ ,$$

where y –observed value,

$y*$ –true, or latent, value,

y_0 –threshold level,

x – vector of independent (explanatory) variables,

β – vector of coefficients to be estimated,

ε – i.i.d. error term drawn from $N(0, \sigma^2)$.

Since the observed dependent variable y_i is not linear in x_i, running OLS on either non-censored observations(i.e. when $y_i = y_i^*$) or a full sample would produce biased estimates of β (Amemiya 1984, pp. 10-11).

The likelihood function for the Tobit model is written as:

$$L = \prod_0 \left[1 - \Phi\left(\frac{x'\beta_i}{\sigma} \right) \right] \prod_1 \frac{1}{\sigma} \phi\left(\frac{y_i - x'\beta_i}{\sigma} \right),$$

where Φ and ϕ are cdf and pdf of standard normal distribution respectively. The first product of the likelihood function "deals" with censored values of y, the second product "deals" with observed values of y. The maximum likelihood estimator (MLE) was proved to be consistent and asymptotically normal. As already discuss in footnote on p. 17, pooled Tobit estimates are also consistent in case of panel data with N fixed and $T \rightarrow \infty$ (Greene 2004).

The marginal effect of independent variable x^k is the partial derivative of the conditional expected value of y_i with respect to that variable: $ME_k = \dfrac{\partial E(y \mid \boldsymbol{x})}{\partial x^k}$.

In a linear model, the marginal effect is simply $\hat{\beta}_{OLS}^k$. Since the Tobit model is not linear, estimates of β do not provide information on the change in *observed* dependent variable y_i when x_i changes by a small amount. Greene (2005, p. 765) derives a general formula for computing marginal effect which can be summarised as follows:

$$ME_k = \frac{\partial E(y \mid \boldsymbol{x})}{\partial x^k} = \hat{\beta}_k \Phi\left(\frac{x_i\beta - y_0}{\sigma} \right).$$

Hence, the marginal effect is roughly the $\hat{\beta}$ estimate times the fraction of non-censored observations in the sample (ibid, p. 766).

Appendix 2. Tables.

Table 1.Ownership of generation companies, at the end of 2008 and 2011.

Company	Capacity, MW	Main shareholder(s), type of business and country for foreign investors	Share in capital as of 31.12.2008		Share in capital as of 31.12.2011
Wholesale generation companies (WGC)					
WGC-1	9,231	RusHydro FSK EES (network grid company)	22.69% 43.10%	InterRAO Gazprombank as entrusted administrator	56.02% 19.00%
WGC-2	8,695	Gazprom subsidiaries	56.61%	[merged with WGC-6, shares are given for the new company] Gazprom subsidiaries InterRAO	 57.25% 5.7%
WGC-3	8,357	Norilsk Nickel (ore mining producer)	60.66%	InterRAO Gazprombank as entrusted administrator	63.93% 18.00%
WGC-4	8,630	E.On (energy, Germany)	76%	E.On (energy, Germany)	78.31%
WGC-5	8,773	Enel (energy, Italy) EBRD Gazprom subsidiaries	55.86% 5.12% 5.27%	Enel (energy, Italy) EBRD InterRAO	56.43% 5.18% 26.43%
WGC-6	9,052	Gazprom subsidiaries FSK EES (network grid company)	42.88% 9.60%	[merger with WGC-2]	
Territorial generation companies (TGC)					
TGC-1	6,287.95	Gazprom (gas monopoly) Fortum (energy, Finland)	28.66% 25.66%	Gazprom (gas monopoly) Fortum (energy, Finland)	51.79% 25.66%
TGC-2	2,576.5	[not reported]		SINTEZ group (holding)	43.82%
TGC-3	11,953	Gazprom (gas monopoly) Moscow government	53.47% 21.16%	Gazprom (gas monopoly) Moscow government InterRAO	53.50% 26.45% 5.05%
TGC-4	3,419.8	Onexim Holding (affiliated with RUSAL aluminium producer)	49.99%	Onexim Holding (affiliated with RUSAL aluminium producer)	49.99%
TGC-5	2,467.3	Integrated Energy Systems Russian Government	46.12% 25.09%	Integrated Energy Systems Russian Government	40.02% 25.09%
TGC-6	3,122.5	FSK EES (IES holding as entrusted administrator) Integrated Energy Systems	19.95% 18.41%	InterRAO Integrated Energy Systems	26.08% 60.04%

TGC-7	5,850.7	Integrated Energy Systems	69.65%	InterRAO Integrated Energy Systems	32.44% 57.5%
TGC-8	2,351	LUKOIL (oil producer)	43.93%	[The company was divided into several smaller producers, keeping LUKOIL as main shareholder, and changed its status from joint-stock to limited, no public info on shares]	
TGC-9	3,309.4	[not reported]		Integrated Energy Systems EBRD	77.34% 7.88%
TGC-10	2,785	Fortum (energy, Finland)	92.9%	Fortum (energy, Finland)	94.5%
TGC-11	2,051	InterRAO	29.89%	InterRAO	67.53%
TGC-12	4,500.2	SUEK holding (coal industry)	49.64%	SUEK holding and subsidiaries	66.13%
TGC-13	2,530	SUEK holding (coal industry)	50.002%	SUEK holding and subsidiaries	61.2%
TGC-14	639.4	Russian Railways company	49.25%	Russian Railways company	83.62%
Energo companies (TGC status)					
TatEnergo	11,315	Tatarstan regional government	100%	Tatarstan regional government	100%
BashkirEnergo	4,556	FSK EES (national grid company) Sistema (financial corporation) and subsidiaries	21.27% 48.87%	InterRAO Sistema (financial corporation)	20.68% 50.16%
NovosibirskEnergo	2,522	[not reported]		[not reported]	
IrkutskEnergo	12,897.9	Federal Government	40%	InterRAO EvroSibEnergo	40% 50.19%

Table 2. The HHI index for free flow zones

The summary table is below, the table with detailed calculations starts on the next page.

Zones with a low share of imports (8 zones in total): 1, 7, 8, 15, 23, 24, 27, 28.

Lower HHI when import is accounted for pro-rata (16 zones in total): 2, 3, 5, 6, 9, 10, 11, 12, 13, 14, 16, 17, 18, 21, 22, 25.

Higher HHI when import is accounted for pro-rata (2 zones): 4 and 19 (practically the same set of suppliers in the given zone and the zones of export).

FFZ index	Total capacity, incl. import, MW	Share of import, %	HHI import as one supplier	HHI import pro-rata
1	36,624	1.3	2,041	2,041
2	3,282	25.9	4,230	3,850
3	2,538	37.8	5,300	4,682
4	1,235	23.1	3,515	5,065
5	1,713	28.8	5,000	4,388
6	2,428	45.6	3,613	2,117
7	27,337	14.0	1,466	1,466
8	12,120	6.3	2,707	2,707
9	705	96.6	9,342	2,937
10	1,389	58.0	4,817	2,438
11	3,001	37.1	3,755	2,782
12	5,153	52.6	3,923	3,063
13	18,702	25.7	2,420	1,964
14	4,799	32.3	2,636	2,104
15	7,231	5.4	3,861	3,861
16	4,313	51.7	3,907	2,498
17	5,234	28.2	3,703	3,300
18	936	48.7	5,003	4,591
19	5,062	22.3	1,741	3,023
20	4,737	34.4	3,975	4,379
21	547	65.6	5,172	3,822
22	935	100	10,000	6,487
23	2,276	21.7	6,602	6,688
24	37,623	13.5	1,606	1,606
25	1,967	66.2	5,417	2,350
26	19,434	23.7	4,445	4,987
27	13,987	15.3	2,418	2,418
28	3,633	0	5,005	5,005
	Weighted HHI		**2,763**	**2,626**

Free flow zone, number and name	Company	Capacity, MW	Share, %	HHI
1 Siberia	*Imports(total)*	458	1.3	2
	TGC-11	471	1.3	2
	WGC-2	1,250	3.4	12
	WGC-4	1,500	4.1	17
	TGC-12	1,837	5	25
	NovosibirskEnergo	2,522	6.9	47
	TGC-13	2,530	6.9	48
	Krasnoyarskaya Hydropower station	6,000	16.4	268
	RusHydro	7,176	19.6	384
	IrkutskEnergo	12,880	35.2	1,237
	Total	**36,624**	**100**	***2,041***
2 Southern Kuzbass	Yuzhno-Kuzbasskaya Thermal Power Station	554	16.9	285
	Imports(total)	850	25.9	670
	TGC-12	1,878	57.2	3,274
	Total (import as one supplier)	**3,282**	**100**	***4,230***
	Imports (from zone 1)			
	TGC-11	11	0.34	0.1
	WGC-2	29	0.90	1
	WGC-4	35	1.07	1
	NovosibirskEnergo	59	1.81	3
	TGC-13	59	1.81	3
	Krasnoyarskaya Hydropower station	141	4.30	18
	RusHydro	169	5.14	26
	IrkutskEnergo	303	9.22	85
	Yuzhno-Kuzbasskaya Thermal Power Station	554	16.9	285
	TGC-12 (import from zone 1)	43	58.5	3,427
	TGC-12 (capacity)	1,878		
	Total (import pro-rata)	**3,282**	**100**	***3,850***
3 Omsk	*Imports(total)*	958	37.8	1,425
	TGC-11	1,580	62.2	3,875
	Total (import as one supplier)	**2,538**	**100**	***5,300***
	Imports (from zone 1)			
	WGC-2	33	1.2	1
	WGC-4	40	1.4	2
	TGC-12	49	1.7	3
	NovosibirskEnergo	67	2.4	6
	TGC-13	67	2.4	6
	Krasnoyarskaya Hydropower station	159	5.6	31
	RusHydro	190	6.7	45

	IrkutskEnergo	341	12.0	145
	TGC-11 (import from zone 1) TGC-11 (capacity)	12 1,878	66.7	4,444
	Total (import pro-rata)	**2,836**	**100**	***4,682***
4 **Chita**	*Imports (total)*	286	23.1	535
	WGC-3	430	34.8	1,213
	TGC-14	519	42	1,767
	Total (import as one supplier)	**1,235**	**100**	***3,515***
	WGC-3 (import from zone 5) WGC-3 (capacity)	258 430	55.7	3,102
	TGC-14 (import from zone 5) TGC-14 (capacity)	28 519	44.3	1,963
	Total (import pro-rata)	**1,235**	**100**	***5,065***
5 **Buryatiya**	TGC-14	120	7	49
	Imports(total)	492	28.8	827
	WGC-3	1,100	64.2	4,124
	Total (import as one supplier)	**1,713**	**100**	***5,000***
	Imports (from zones 1)			
	TGC-11	6	0.4	0.1
	WGC-2	17	1.0	1
	WGC-4	20	1.2	1
	TGC-12	24	1.4	2
	NovosibirskEnergo	33	2.0	4
	TGC-13	34	2.0	4
	Krasnoyarskaya Hydropower station	80	4.6	22
	RusHydro	95	5.6	31
	IrkutskEnergo	171	10.0	99
	TGC-14 (import from zone 4) TGC-14 (capacity)	7 120	7.4	55
	WGC-3 (import from zone 4) WGC-3 (capacity)	6 1,100	64.6	4,171
	Total (import pro-rata)	**1,712**	**100**	***4,388***
6 **Altay**	Biyskaya CHP	535	22	486
	TGC-12	785	32.3	1,046
	Imports(total)	1,107	45.6	2,081
	Total (import as one supplier)	**2,428**	**100**	***3,613***
	Imports (from zones 1)			
	TGC-11	14	0.6	0.4
	WGC-2	38	1.6	2
	WGC-4	46	1.9	4
	NovosibirskEnergo	77	3.2	10
	TGC-13	77	3.2	10

	Krasnoyarskaya Hydropower station	184	7.6	57
	RusHydro	220	9.1	82
	IrkutskEnergo	394	16.2	264
	Biyskaya CHP	535	22.0	486
	TGC-12 (import from zone 1)	56	34.7	1,201
	TGC-12 (capacity)	785		
	Total (import pro-rata)	**2,427**	**100**	***2,117***
7 Ural	Kurganskaya CHP	222	0.8	1
	WGC-4	600	2.2	5
	RosEnergoAtom	600	2.2	5
	WGC-3	882	3.2	10
	TGC-7	1,020	3.7	14
	TGC-10	1,106	4	16
	TGC-9	1,168	4.3	18
	WGC-2	2,059	7.5	57
	Imports (from zones 8, 10, 11, 12 and 13)	3,815	14	195
	BashkirEnergo	4,556	16.7	278
	WGC-5	4,982	18.2	332
	WGC-1	6,327	23.1	536
	Total	**27,337**	**100**	***1,466***
8 Tyumen	*Imports*	761	6.3	39
	WGC-1	1,600	13.2	174
	TGC-10	1,679	13.9	192
	WGC-2	3,280	27.1	732
	WGC-4	4,800	39.6	1,569
	Total	**12,120**	**100**	***2,707***
9 Northern Tyumen	WGC-1	24	3.4	12
	Imports	681	96.6	9,330
	Total (import as one supplier)	**705**	**100**	***9,342***
	Imports (from zone 8)			
	TGC-10	101	14.3	204
	WGC-2	197	27.9	778
	WGC-4	288	40.8	1,666
	WGC-1(import from zone 8)	96	17.0	289
	WGC-1(capacity)	24		
	Total (import pro-rata)	**705**	**100**	***2,937***
10 Serovo-Bogoslovskaya	TGC-9	57	4.1	17
	WGC-2	526	37.9	1,434
	Imports	806	58	3,367
	Total (import as one supplier)	**1,389**	**100**	***4,817***
	Imports (from zone 7)			
	Kurganskaya CHP	8	0.5	0.3
	WGC-4	21	1.5	2

	RosEnergoAtom	21	1.5	2
	WGC-3	30	2.2	5
	TGC-7	35	2.5	6
	TGC-10	38	2.7	7
	BashkirEnergo	156	11.2	126
	WGC-5	171	12.3	151
	WGC-1	217	15.6	244
	TGC-9 (import from zone 7)	40	7.0	49
	TGC-9 (capacity)	57		
	WGC-2 (import from zone 7)	71	42.9	1,845
	WGC-2 (capacity)	526		
	Total (import pro-rata)	**1,389**	**100**	***2,438***
11 Perm	RusHydro	519	17.3	299
	Imports(total)	1,113	37.1	1,376
	TGC-9	1,368	45.6	2,080
	Total (import as one supplier)	**3,001**	**100**	***3,755***
	Import (from zone 7)			
	Kurganskaya CHP	10	0.3	0.1
	WGC-4	26	0.9	1
	RosEnergoAtom	26	0.9	1
	WGC-3	38	1.3	2
	TGC-7	44	1.5	2
	TGC-10	47	1.6	2
	WGC-2	88	2.9	9
	BashkirEnergo	195	6.5	42
	WGC-5	214	7.1	51
	WGC-1	271	9.0	82
	Import (from zone 12)			
	TGC-5	61	2.0	4
	TGC-9 (import from zone 7)	50	47.3	2,234
	TGC-9 (capacity)	1,368		
	RusHydro (import from zone 12)	44	18.8	352
	RusHydro (capacity)	519		
	Total (import pro-rata)	**3,000**	**100**	***2,782***
12 Vyatka	RusHydro	1,020	19.8	392
	TGC-5	1,420	27.6	760
	Imports(total)	2,713	52.6	2,772
	Total (import as one supplier)	**5,153**	**100**	***3,923***
	Import (from zones 7, 11, 13, 14 and 24)			
	Urusinkaya Thermal Power Station (import from zone 13)	6	0.2	0.02
	Kurganskaya CHP (import from zone 7)	8	0.2	0.05
	InterRAO (import from zone 24)	12	0.3	0.10
	Mobilnye GTES company (import from zone	12	0.3	0.11

	24)			
	WGC-4 (import from zones 7 and 24)	44	1.2	1
	TGC-10 (import from zone 7)	40	1.1	1
	TGC-2 (import from zone 24)	54	1.4	2
	TGC-9 (import from zones 7 and 11)	92	2.5	6
	TGC-6 (import from zones 13 and 24)	113	3.0	9
	TGC-4 (import from zone 24)	124	3.3	11
	BashkirEnergo (import from zone 7)	165	4.4	19
	WGC-2 (import from zones 7 and 24)	181	4.9	24
	TGC-7 (import from zone 7 and 13)	195	5.2	27
	WGC-3 (import from zones 7 and 24)	208	5.6	31
	WGC-1 (import from zone 7)	229	6.1	37
	TatEnergo (import from zones 13 and 14)	241	6.5	42
	WGC-5 (import from zones 7 and 24)	269	7.2	52
	RosEnergoAtom (import from zones 7 and 24)	448	12.0	144
	RusHydro (import from zones 11, 13, 14 and 24)	235	33.6	1,130
	RusHydro (capacity)	1,020		
	TGC-5 (import from zone 14)	38	39.1	1,525
	TGC-5 (capacity)	1,420		
	Total (import pro-rata)	**3,733**	**138**	***3,063***
13 Volga	Urusinkaya Thermal Power Station	161	0.9	1
	TGC-6	745	4	16
	RusHydro	2,776	14.8	220
	TGC-7	4,372	23.4	546
	Imports(total)	4,803	25.7	660
	TatEnergo	5,845	31.3	977
	Total (import as one supplier)	**18,702**	**100**	***2,420***
	Imports (from zones 7, 12, 14, 15 and 24)			
	Kurganskaya CHP (import from zone 7)	16	0.1	0.0
	InterRAO (import from zone 24)	23	0.1	0.0
	Mobilnye GTES company (import from zone 24)	24	0.1	0.0
	TGC-10 (import from zone 7)	77	0.4	0.2
	WGC-4 (import from zones 7 and 24)	86	0.5	0.2
	TGC-5 (import from zones 12 and 14)	173	0.9	0.9
	TGC-2 (import from zone 24)	105	0.6	0.3
	TGC-9 (import from zone 7)	82	0.4	0.2
	TGC-4 (import from zone 24)	239	1.3	2
	BashkirEnergo (import from zone 7)	319	1.7	3
	WGC-2 (import from zones 7 and 24)	351	1.9	4
	WGC-3 (import from zones 7 and 24)	404	2.2	5
	WGC-1 (import from zone 7)	443	2.4	6
	WGC-5 (import from zones 7 and 24)	522	2.8	8
	RosEnergoAtom (import from zones 7, 15	1,148	6.1	38

	and 24)			
	Urusinkaya Thermal Power Station	161	0.9	1
	TGC-6 (import from zone 24)	167	4.9	24
	TGC-6 (capacity)	745		
	RusHydro (import from zones 12, 14, 15 and 24)	391	16.9	287
	RusHydro (capacity)	2,776		
	TGC-7 (import from zones 7 and 15)	175	24.3	591
	TGC-7 (capacity)	4,372		
	TatEnergo (import from zone 14)	58	31.6	996
	TatEnergo (capacity)	5,845		
	Total (import pro-rata)	**18,702**	**100**	***1,964***
14 Kinderi	TatEnergo	830	17.3	299
	TGC-5	1,047	21.8	476
	RusHydro	1,370	28.5	815
	Imports(total)	1,552	32.3	1,046
	Total (import as one supplier)	**4,799**	**100**	***2,636***
	Import (from zones 12, 13 and 24)			
	Urusinkaya Thermal Power Station (import from zone 13)	5	0.1	0
	InterRAO (import from zone 24)	10	0.2	0
	Mobilnye GTES company (import from zone 24)	11	0.2	0
	WGC-4 (import from zone 24)	20	0.4	0
	TGC-2 (import from zone 24)	47	1.0	1
	WGC-5 (import from zone 24)	79	1.6	3
	WGC-2 (import from zone 24)	94	2.0	4
	TGC-6 (import from zones 13 and 24)	99	2.1	4
	TGC-4 (import from zone 24)	109	2.3	5
	TGC-7 (import from zone 13)	139	2.9	8
	WGC-3 (import from zone 24)	155	3.2	10
	RosEnergoAtom (import from zone 24)	375	7.8	61
	TatEnergo (import from zone 13)	186	21.2	448
	TatEnergo (capacity)	830		
	TGC-5 (import from zone 12)	45	22.8	518
	TGC-5 (capacity)	1,047		
	RusHydro (import from zones 12, 13 , 24)	179	32.3	1,042
	RusHydro (capacity)	1,370		
	Total (import pro-rata)	**4,799**	**100**	***2,104***
15 Balakovo	*Imports(total)*	392	5.4	29
	RusHydro	1,360	18.8	354
	TGC-7	1,479	20.5	418
	RosEnergoAtom	4,000	55.3	3,060
	Total (import as one supplier)	**7,231**	**100**	***3,861***
16	RusHydro	793	18.4	338

Caucasus	WGC-5	1,290	29.9	894
	Imports(total)	2,231	51.7	2,674
	Total (import as one supplier)	**4,313**	**100**	***3,907***
	Import (from zones 19, 20, 21 and 23)			
	InterRAO (import from zone 21)	39	0.9	1
	RosEnergoAtom (import from zone 19)	248	5.7	33
	TGC-8 (import from zones 19, 20 and 21)	385	8.9	80
	WGC-2 (import from zones 19 and 20)	1,118	25.9	671
	WGC-5	1,290	29.9	894
	RusHydro (import from zones 23)	441	28.6	819
	RusHydro (capacity)	793		
	Total (import pro-rata)	**4,314**	**100**	***2,498***
17 Volgograd	TGC-8	1,205	23	530
	Imports(total)	1,478	28.2	797
	RusHydro	2,551	48.7	2,376
	Total (import as one supplier)	**5,234**	**100**	***3,703***
	Import (from zones 15, 18, 19 and 24)			
	InterRAO (import from zone 24)	11	0.2	0.04
	Mobilnye GTES company (import from z.24)	11	0.2	0.05
	WGC-4 (import from zone 24)	21	0.4	0.17
	TGC-7 (import from zone 15)	50	1.0	1
	TGC-2 (import from zone 24)	50	1.0	1
	TGC-6 (import from zone 24)	80	1.5	2
	WGC-5 (import from zone 24)	84	1.6	3
	TGC-4 (import from zone 24)	115	2.2	5
	WGC-3 (import from zone 24)	165	3.1	10
	WGC-2 (import from zones 19 and 24)	171	3.3	11
	RosEnergoAtom (import from zones 15, 19 and 24)	567	10.8	117
	TGC-8 (import from zones 18 and 19)	44	23.9	569
	TGC-8	1,205		
	RusHydro (import from zones 15 and 24)	108	50.8	2,581
	RusHydro	2,551		
	Total (import pro-rata)	**5,234**	**100**	***3,300***
18 Kaspiy	*Imports (total)*	456	48.7	2,373
	TGC-8	480	51.3	2,630
	Total (import as one supplier)	**936**	**100**	***5,003***
	Import (from zones 17 and 19)			
	RusHydro (import from zone 17)	151	16.2	261
	RosEnergoAtom (import from zone 19)	59	6.3	40
	WGC-2 (import from zone 19)	125	13.4	179
	TGC-8 (import from zones 17 and 19)	120	64.1	4,110
	TGC-8 (capacity)	480		
	Total (import pro-rata)	**936**	**100**	***4,591***

19 Rostov	TGC-8	819	16.2	262
	RosEnergoAtom	1,000	19.8	390
	Imports(total)	1,131	22.3	499
	WGC-2	2,112	41.7	1,741
	Total (import as one supplier)	**5,062**	**100**	***2,892***
	Import (from zones 16, 17, 18, 20 and 23)			
	WGC-5 (import from zone 16)	130	2.4	6
	RusHydro (import from zones 16, 17, 23)	517	9.7	94
	RosEnergoAtom (capacity)	1,000	18.7	351
	TGC-8 (import from zones 17, 18 and 20)	517	25.0	627
	TGC-8 (capacity)	819		
	WGC-2 (import from zone 20)	242	44.1	1,945
	WGC-2 (capacity)	2,112		
	Total (import pro-rata)	**5,338**	**100**	***3,023***
20 Kuban'	TGC-8	706	14.9	222
	Imports	1,632	34.4	1,186
	WGC-2	2,400	50.7	2,567
	Total (import as one supplier)	**4,737**	**100**	***3,975***
	Import (from zones 16, 19 and 21)			
	InterRAO (import from zone 21)	42	0.9	1
	RusHydro (import from zone 16)	209	4.4	19
	RosEnergoAtom (import from zone 19)	263	5.6	31
	WGC-5 (import from zone 16)	339	7.2	51
	TGC-8 (import from zones 19 and 21)	223	19.6	385
	TGC-8 (capacity)	706		
	WGC-2 (imports from zone 19)	556	62.4	3,892
	WGC-2 (capacity)	2,400		
	Total (import pro-rata)	**4,738**	**100**	***4,379***
21 Sochi	TGC-8	30	5.5	30
	InterRAO	158	28.9	834
	Imports(total)	359	65.6	4,308
	Total (import as one supplier)	**547**	**100**	***5,172***
	Import (from zone 20)			
	WGC-2	277	50.7	2,572
	TGC-8 (import from zone 20)	82	20.4	416
	TGC-8 (capacity)	30		
	InterRAO	158	28.9	834
	Total (import pro-rata)	**547**	**100**	***3,822***
22 Gelendzhik	*Imports (total)*	935	100	10,000
	Total (import as one supplier)	**935**	**100**	***10,000***
	Import (from zone 20)			
	TGC-8	213	22.7	517
	WGC-2	722	77.3	5,971

	Total (import pro-rata)	**935**	**100**	***6,487***
23 Derbent	*Imports*	494	21.7	471
	RusHydro	1,782	78.3	6,132
	Total (import as one supplier)	**2,276**	**100**	***6,602***
	Import (from zones 16 and 19)			
	TGC-8 (import from zone 19)	67	3.0	9
	WGC-5 (import from zone 16)	106	4.7	22
	WGC-2 (import from zone 19)	173	7.6	58
	RosEnergoAtom (import from zone 19)	82	3.6	13
	RusHydro (import from zone 16)	65	81.2	6,586
	RusHydro (capacity)	1,782		
	Total (import pro-rata)	**2,276**	**100**	***6,688***
24 Centre	InterRAO	325	0.9	1
	Mobilnye GTES company	338	0.9	1
	WGC-4	630	1.7	3
	TGC-2	1,494	4	16
	RusHydro	1,840	4.9	24
	TGC-6	2,378	6.3	40
	WGC-5	2,475	6.6	43
	WGC-2	2,960	7.9	62
	TGC-4	3,420	9.1	83
	WGC-3	4,885	13	169
	Imports(from zones 12, 13, 14, 15, 17, 25, 26, 27)	5,079	13.5	182
	RosEnergoAtom	11,800	31.4	984
	Total (import as one supplier)	**37,623**	**100**	***1,606***
25 Vologda	TGC-2	34	1.7	3
	WGC-2	630	32	1,025
	Imports(total)	1,303	66.2	4,389
	Total (import as one supplier)	**1,967**	**100**	***5,417***
	Import (from zones 24 and 27)			
	Mobilnye GTES company (import from zone 24)	10	0.5	0.3
	WGC-4 (import from zone 24)	18	0.9	1
	InterRAO (from zones 24 and 27)	36	1.8	3
	RusHydro (import from zone 24)	54	2.7	8
	TGC-6 (import from zone 24)	70	3.5	13
	WGC-5 (import from zone 24)	73	3.7	14
	TGC-4 (import from zone 24)	100	5.1	26
	TGC-1 (import from zone 27)	130	6.6	43
	WGC-3 (import from zone 24)	143	7.3	53
	RosEnergoAtom (import from zones 24 and 27)	464	23.6	556
	TGC-2 (import from zone 24)	44	4.0	16
	TGC-2 (capacity)	34		

	WGC-2 (import from zones 24 and 27)	161	40.2	1,618
	WGC-2 (capacity)	630		
	Total (import pro-rata)	**1,967**	**100**	***2,350***
26 Moscow	MOEK company	191	1	1
	WGC-4	1,100	5.7	32
	WGC-1	1,580	8.1	66
	Imports	4,610	23.7	563
	TGC-3	11,953	61.5	3,783
	Total (import as one supplier)	**19,434**	**100**	***4,445***
	Import (from zones 24 and 27)			
	Mobilnye GTES company (import from zone 24)	35	0.2	0.03
	InterRAO (from zones 24 and 27)	127	0.7	0.43
	TGC-2 (import from zone 24)	155	0.8	1
	RusHydro (import from zone 24)	191	1.0	1
	TGC-6 (import from zone 24)	247	1.3	2
	WGC-5 (import from zone 24)	257	1.3	2
	TGC-4 (import from zone 24)	355	1.8	3
	TGC-1 (import from zone 27)	459	2.4	6
	WGC-3 (import from zone 24)	507	2.6	7
	WGC-2 (import from zones 24 and 27)	570	2.9	9
	RosEnergoAtom (import from zones 24 and 27)	1,641	8.4	71
	MOEK company	191	1.0	1
	WGC-4 (import from zone 24)	65	6.0	36
	WGC-4 (capacity)	1,100		
	WGC-1	1,580	69.6	4,849
	TGC-3	11,953		
	Total (import pro-rata)	**19,434**	**100**	***4,987***
27 West	InterRAO	900	6.4	41
	Imports(from zones 24, 25, 26 and 28)	2,142	15.3	235
	WGC-2	2,530	18.1	328
	RosEnergoAtom	4,000	28.6	818
	TGC-1	4,415	31.6	996
	Total	**13,987**	**100**	***2,418***
28 Kol'skaya	RosEnergoAtom	1,760	48.4	2,347
	TGC-1	1,873	51.6	2,658
	Total	**3,633**	**100**	***5,005***

Table 3. Mean value of Lerner index by zones.

Free flow zone	Lerner index, %		Delta in mean values, $\overline{LI}_{2010} - \overline{LI}_{2011}$, p.p. (positive value = decrease in market power index over time)
	2010	2011	
1	46	44	2
2	21	23	-2
3	19	15	4
4	-20	-20	0
5	-21	-19	-2
6	6	-8	14
7	21	21	0
8	34	28	6
9	17	7	10
10	14	11	3
11	62	50	12
12	29	29	0
13	64	63	1
14	66	59	7
15	100	100	0
16	38	29	9
17	95	97	-2
18	26	24	2
19	12	10	2
20	17	16	0
21	19	18	1
22	22	19	3
23	100	100	0
24	38	35	3
25	11	8	3
26	30	28	2
27	53	46	7
28	99	100	-1

Table 4. Fitting hourly trend (two-year sample)

FFZ	Intercept	Slope * 10^6
1	0.42	3.56
2	0.19	3.76
3	0.19	-2.30
4	-0.23	4.35
5	-0.25	5.76
6	0.09	-10.99
7	0.21	-0.59
8	0.37	-7.14
9	0.22	-11.26
10	0.12	**0.17**
11	0.63	-8.38
12	0.29	0.12
13	0.61	2.70
14	0.65	-2.90
15	1.00	-0.18
16	0.41	-9.08
17	0.94	1.94
18	0.25	**0.19**
19	0.14	-3.32
20	0.19	-2.27
21	0.21	-2.48
22	0.25	-5.23
23	1.00	-0.43
24	0.40	-3.93
25	0.11	-1.78
26	0.31	-2.05
27	0.54	-4.30
28	0.99	0.25

Note: trend coefficient is not significant for zones 10 and 18, so the DF test for these two zones is performed with intercept and no trend (see the following table 5).

Table 5. Unit root test statistics.

Reported are *t-statistics* for the Dickey-Fuller test. For all zones and all periods the DT test rejects the unit root hypothesis at 1%.

The time frame is the full sample, 2 one-year samples and 4 half-year samples. The one-year periods correspond to a year preceding and a year following the market liberalisation. The half years in 2010 correspond to the liberalisation schedule (regulated sector 50% from January 2010 and 20% from July 2010), the half years in 2011 are given for comparison.

(1) All zones except no. 10 and 18, model with a constant and trend: $\Delta y_t = a_0 + a_1 t + \beta y_{t-1} + \varepsilon_t$
Null hypothesis: $\beta = 0$ against Alternative: $\beta < 0$
For the sample size of 100, the critical value at 1% is (-4.04).

(2) FFZ number 10 and 18, model with a constant but without a trend, $\Delta y_t = a_0 + \beta y_{t-1} + \varepsilon_t$
Null hypothesis: $\beta = 0$ against Alternative: $\beta < 0$
For the sample size of 100, the critical value at 1% is (-3.51).

FFZ	All sample	One year		Half-year			
		2010	2011	Jan-June 2010	Jul-Dec 2010	Jan-Jun 2011	Jul-Dec 2011
1	-46	-33	-27	-27	-27	-21	-23
2	-32	-23	-21	-15	-17	-15	-15
3	-40	-23	-30	-17	-17	-18	-26
4	-29	-19	-20	-16	-13	-13	-16
5	-36	-21	-28	-19	-14	-18	-21
6	-40	-26	-27	-17	-20	-18	-21
7	-28	-16	-17	-12	-13	-11	-14
8	-28	-17	-20	-13	-15	-14	-15
9	-26	-16	-18	-12	-12	-12	-13
10	-30	-14	-21	-16	-7	-17	-14
11	-58	-39	-38	-37	-41	-36	-36
12	-75	-41	-41	-30	-37	-29	-34
13	-62	-42	-38	-41	-41	-35	-37
14	-36	-21	-21	-22	-22	-21	-22
15	-111	-94	-78	-66	-66	-143	-56
16	-54	-34	-37	-28	-26	-25	-29
17	-70	-45	-46	-34	-30	-33	-34
18	-26	-12	-17	-10	-8	-9	-15
19	-40	-23	-26	-17	-17	-16	-20
20	-48	-26	-31	-18	-22	-18	-24
21	-47	-27	-30	-22	-20	-17	-23
22	-41	-24	-27	-17	-19	-15	-20
23	-92	-76	-51	-47	-67	-30	-37
24	-56	-41	-40	-36	-37	-33	-36
25	-39	-24	-29	-15	-20	-16	-23
26	-38	-20	-26	-17	-14	-16	-20
27	-38	-20	-28	-21	-21	-22	-31
28	-80	-48	-81	-36	-34	-47	-59

Table 6. Explanatory variables of the Tobit regression

Variable	Dummy/ Continuous	Dummy values/ Units	Comments	Source
Share of regulated contracts	Continuous	Per cent	Ratio of regulated contract for electricity sale in the price zone relative to the total sales (there is no data for FFZ)	Commercial Operator, author's calculations
Share of free contracts	Continuous	Per cent	Ratio of free contracts for electricity sale in the price zone relative to the total sales (there is no data for FFZ)	Commercial Operator, author's calculations
Hour type	Dummy	Off-peak (base), shoulder and peak hour.	Precise hour type is defined by the System Operator (depends on daylight timing and day of the week/public holiday)	System Operator
Season	Dummy	Summer (base): from April 1st to September 30 Winter: from October 1st to March 31st	Captures the use of central heating systems (CHP plants in heat mode during winter and in thermal mode during summer)	
Air temperature	Continuous	Degree centigrade	Captures the demand fluctuation. 1) Actual time series have 3-hour frequency, (at 0, 3, 6 etc. hours). Values for hours 1 and 2 are set the same as for hour 0; for hours 4 and 5 – same as for hour 3, etc. 2) Actual time series are available for cities/towns; we consider cities which are centres of administrative regions. When an FFZ consists of several administrative regions, the temperature series of the cities are weighted by population in the given region.*	Temperature: Weather online archive of SMIS Lab, Russian Academy of Sciences** Population: Russian Federal Statistics Service
Air temperature squared	Continuous	Degree centigrade squared	Captures the impact of extreme values	
FFZ index	Dummy	Index 1…28; Base is FFZ #24 'Centre' (in the European part of Russia)	Captures fixed effects including local climate, generation mix and transmission constraints.	

* Method for estimating air temperature variable using actual values and people's population as weights was used in Bask et al. (2011)

** SMIS Lab – Space Monitoring Information Support Laboratory, Space Research Institute, Russian Academy of Sciences.

Table 7. Tobit regressions – difference specifications.

(1) Hour and season dummies separately, no FFZ index

(2) Hour and season dummies separately, with FFZ index

(3) Hour type and season – interaction, with FFZ index

	(1)	(2)	(3)	
	Coefficient	Coefficient	Coefficient	Marginal effect
Share of regulated contracts	-0.032	0.055	0.052	0.0415
Share of free contracts	-1.952	-0.015(*)	-0.035	-0.0279
Shoulder hour	5.361	7.628		
Peak hour	5.284	7.535		
Winter	5.315	7.802		
Off peak hour * winter			16.539	10.470
Shoulder hour * summer			12.053	9.260
Shoulder hour * winter			20.241	12.847
Peak hour * summer			13.429	10.439
Peak hour * winter			19.238	11.382
Air temp	0.549	0.190	0.215	0.172
(Air temp)^2	-0.007	0.006	0.008	0.006
FFZ dummies	no	yes	yes	
Constant	50.916	24.712	22.113	17.637
Sigma (std deviation of residuals)	45.469	24.944	24.878	
Log likelihood	-2,130,947	-1,834,130	-1,832,201	
Pseudo R2	0.0156	0.1528	0.1536	

(*) Not statistically significant even at 10%

Table 8. Tobit regression for years 2010 and 2011

Third specification from table 7.

	2010		2011	
	Coefficient	**Marginal effect**	**Coefficient**	**Marginal effect**
Share of regulated contracts	-0.685	-0.662	0.167	0.160
Share of free contracts	-0.915	-0.883	-0.681	-0.653
Off peak hour * winter	10.708	10.332	19.234	18.458
Shoulder hour * summer	10.022	9.670	13.579	13.031
Shoulder hour * winter	15.177	14.644	22.933	22.007
Peak hour * summer	11.570	11.164	14.448	13.864
Peak hour * winter	12.668	12.232	21.188	20.333
Air temp	0.296	0.284	0.062	0.060
(Air temp)^2	0.003	0.003	0.005	0.005
FFZ dummies	yes		yes	
Constant	60.582	58.454	21.534	20.665
Sigma (std deviation of error term)	24.374		24.563	
Log likelihood	-907,126		-919,199	
Pseudo R2	0.1562		0.1563	