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Market Power and Power Markets: Structural Problems of Russian Wholesale Electricity Market

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Abstract

According to the basic guidelines on reforming the electricity sector, approved by Russian Government, after several years the formation of the competitive wholesale power market in Russia will be finished and the regulation of tariffs for power will be terminated. The introduction of the competitive restructuring in the electricity industry inspired a set of concerns about the market power. Large firms may find it profitable to reduce output, exhaust the capacity of competitors, and exploit their dominant position on the residual demand. However, Russian Government and RAO EES plan several merges in the industry, e.g. in Middle Volga and Northwest region, which will increase market power of new entities and will lead to electricity price growth. Authors will examine using supply function equilibrium approach the consequence for efficiency of different choice for the structure of the industry in terms of suppliers concentration after the reform and the possible need for regulation.

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OBJECTIVES

Basic Guidelines on Reforming the Electricity Sector of the Russian Federation was approved by government on July, 11 2001 [30]. During the first stage of reform (within 3 years) mechanisms for a competitive wholesale power market will be developed. About 5-15% of electricity will be traded at the wholesale market at non-regulated price. Second stage of the reform will take 2-3 years and it will be the period of introduction of the wholesale and retail power markets within the European, Urals and Siberian energy zones. At that stage the formation of the competitive wholesale power market will be finished, the regulation of tariffs for power will be terminated and regulation of tariffs for transmission and system services will be retained.

The main purpose of this research is to apply economic theory and empirical methods to the analysis of electricity markets, and to analyze proposed changes in Russian market structure and evaluate them in light of theoretical considerations and empirical evidence. As a result, we can find the scope for rising prices above the efficient level and possible structural changes to reduce this inefficiency to modest levels.

CURRENT DEBATE

Previous works have identified non price-taking behavior of firms in deregulated electricity markets. By analyzing comparative static relationships implied by theoretical models of oligopoly pricing, Puller (2001) estimates behavioral models of firm conduct and finds strong evidence that firms do not behave as price-takers but rather exercise static market power. Direct measures of price-cost margins in the UK market (Wolfram(1998)) and the California market (Borenstein, Bushnell, and Wolak (2000)) find prices higher than those associated with Bertrand pricing but lower than levels associated with joint profit maximization. Models of dynamic interaction show that firms in an industry with entry barriers can sustain prices higher than one-shot equilibrium levels. If demand shocks are not observed ex post, Green and Porter (1984) show that firms can sustain prices above Cournot levels during periods of high demand but may revert to static equilibrium prices following negative demand shocks. However, if demand and prices are observed ex post, firms always can sustain the collusive regime but the level of collusion will depend upon current and expected future demand (Rotemberg and Saloner (1986), Haltiwanger and Harrington (1991)) and whether firms face capacity constraints (Brock and Scheinkman (1985)). For example, if current demand is high, the incentives to cut the price and earn deviation profits are high, so the price must be lowered to check that incentive. Similarly, if demand is expected to rise in the near future, the future collusive profits may be higher and firms have less incentive to deviate and start a price war. Johnsen, Verma, and Wolfram (1999) found some empirical evidence that prices in local markets are higher during constrained periods when demand is less elastic in the day-ahead electricity market in Norway.

Wolak (1997) argues that the market rules governing the operation of a restructured electricity market in combination with its market structure can have a substantial impact on the behavior of market-clearing prices. Using evidence on the design of electricity markets in England and Wales, Norway, the state of Victoria in Australia and New Zealand, he illustrates that market structure and market rules are important drivers of the behavior of prices in a competitive electricity market. One conclusion to emerge from this comparison is that there are many differences in how these markets in each country are organized. He also provides an assessment of the relationship between market rules and market structure and the behavior of prices in each market.

The introduction of competitive restructuring in the electricity industry inspired a new set of concerns about market power. In USA and UK even in areas with significant independent and municipally owned generation capacity, large firms may still find it profitable to reduce output, exhaust the capacity of these competitors, and exploit their dominant position on the residual demand.[1] Con-

[1] Von der Fehr and Harbord (1993) argue that these considerations are result of the nature of competition in the United Kingdom. Wolak and Patrick (1997) provide empirical evidence that supports this argument.

cerns over market power in USA had been sufficient to prevent a proposed merger between Southern California Edison and San Diego Gas & Electric Co. in 1989.[1] In Russia the structural changes have already started. We should analyze the consequences of those structural changes before the market liberalization, not after. In this research we will analyze the possible structures and competitive outlook of the Russian electricity market. The results of our research will help to compare different ways of structural changes and divestitures in terms of electricity prices and market power.

Similarly, before privatization in the UK, a number of commentators examined the consequence for efficiency of different choice for the structure of the industry after the privatization and the possible need for regulation. Henney (1987) argued that the CEGB should be split into nine or 10 separate companies and that none of these should be allow to grow subsequently to the point at which it would supply more than 20 percent of market. Sykes and Robinson (1987) claimed that Henney's proposal could not be accomplished within the time scale required by political considerations, but they proposed another mechanism that would have eventually created five or six competing generators. However, it was believed that the two major generating companies - National Power and PowerGen - would compete on price as 'Bertrand' oligopolists, and the resulting fierce competition would result in prices being bid down to near marginal costs. And second, that free entry into generation - in particular using high-efficiency combined cycle gas turbine technology (CCGTs) - would be simple and quick and place further strong competitive pressures on the incumbent generators to price competitively. These expectations have not been borne out by experience however. Pool prices in England and Wales have been significantly higher than they would have been in a competitive market, and the regulator has now intervened on numerous occasions to prevent certain types of manipulation of the pool pricing mechanism from occurring. So, it is reasonable to analyze

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[1] See Frankena and Owen (1994)

the possible behavior of generation companies in Russia and the structure of wholesale electricity market before the end of the reform.

DESCRIPTION OF THE RUSSIAN WHOLESALE MARKET

Goals of the restructuring energy sector in Russia

Goals and prerequisites of the reform have evolved a lot of debates about conception of restructuring, as a result, more than 10 conceptions of restructuring were created. Andersen report (2001) contains goals and prerequisites approved by Government of Russia and RAO UES Rossii. Below we refer to most important ones:

1. Without substantial increases in electricity supply and/or decrease in projected demand, and improved operational management, Russian regions may suffer severe electricity shortages as early as the winter of 2002-3.
2. Russia's electricity industry is stagnant and inefficient and unless fundamentally reformed, its inefficient operation and investment will impose increasingly substantial, unnecessary cost on the Russian economy.
3. Actions of the Government of Russia over the past 9 years are largely responsible for the industry's poor condition and dangerous prospects as it:
   - Failed to put effective independent regulatory arrangements in place.
   - Failed to privatize control of electricity generation and supply companies, which would have enabled these companies to attract private capital, technology and management, and the Government of Russia to have introduced competition into the sector.
   - Allowed chronic nonpayment by budget-funded customers, protected by political intervention at both local and Federal levels.
4. RAO UES Rossii ("UES"), which dominates the sector, must be promptly and substantially restructured to improve efficiency and attract necessary investment. UES cannot

be efficiently managed with its current structure and state control. Such restructuring should clearly separate the High Voltage and Low Voltage networks and dispatch businesses (natural monopolies) from the generation and supply businesses (potentially competitive) of UES and the Energos.

5. Such UES restructuring may reduce required investment in non-nuclear generation capacity to less than UES's currently expected $35 billion through 2010. However, such required investment is still likely to be at least $15-20 billion. In addition, smaller but still substantial investments are required for rehabilitation and development of electricity and heat networks.
6. Substantial increases in tariffs, 1.5 to 2.5 times year 2000 levels when measured in $US at market exchange rates, will be required to make essential new, privately-financed investments economically viable.
7. The Government of Russia can keep electricity prices down only by introducing real, vigorous competition among generators and suppliers.
8. The Government of Russia can attract necessary investment only if price formation is credible and objective, free of political manipulation and allows investors to earn a market return on capital invested. This requires:
   - Market-based pricing of services wherever possible, and
   - Credible market-based regulation of the natural monopolies where direct market-based pricing is not feasible.
9. The goals of achieving real competition and market-based pricing require that UES be unbundled into viable, competing generation and supply companies and that control of those companies be privatized as soon as practicable.

10. The goal of credible regulation requires that the current system of administrative regulation embodied in the FEC/REC structure be replaced by a qualitatively more objective, license-based regulatory scheme.

Market structure

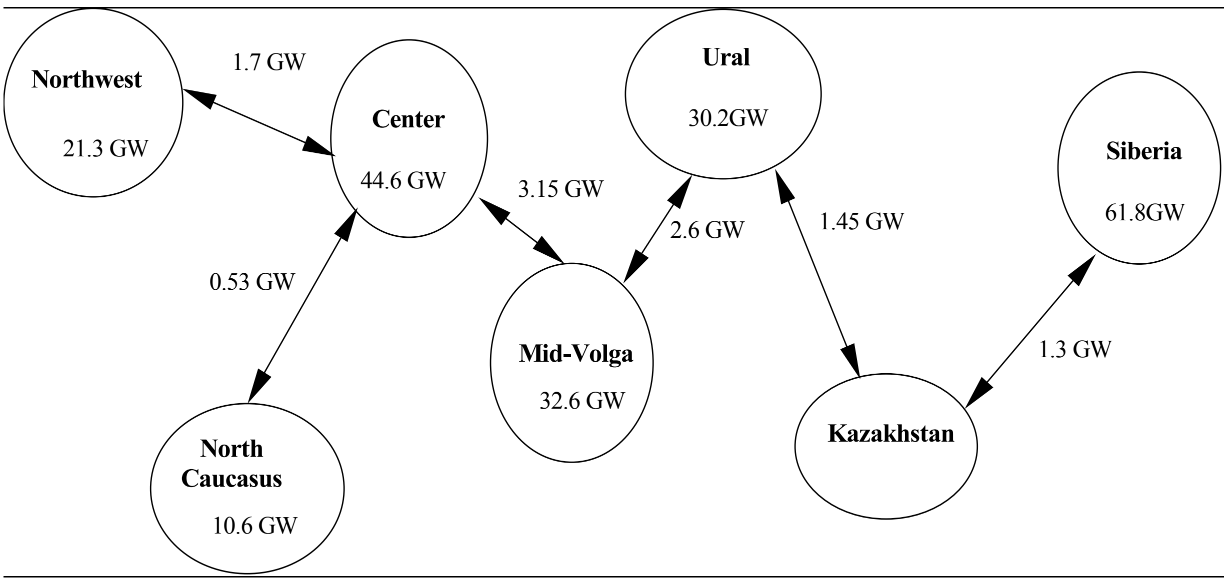
Structural problems can make a good market design impossible. Structure refers primarily to the concentration of suppliers in a market, but it also includes other characteristics that determine a market's basic competitiveness. While market architecture and rules can improve competitiveness, there is no design capable of making a market workably competitive if its structure is too problematic. In that case, either the market must be regulated or the structure improved. Market structure refers to aspects of the market that cannot be designed but can be influenced by laws and regulation. These aspects include the concentration of suppliers and the elasticity of demand. Several mechanical indicators of market structure exist, such as the Herfindahl-Hirschman Index (HHI), but they give only a most limited indication of a power market's structure. Generally, market structure affects the basic competitiveness of the market. Supplier concentration is the structural component most subject to scrutiny and is the focus of most anti-trust law.

Now the main actors in the Russian electricity sector are the joint stock company Unified Electrical Power System of Russia" (RAO UES) and the 72 Regional Distribution Companies (energos). The complicated ownership and operational relationship between them is in part due to trade-offs between central and regional interests. The Russian power system includes approximately 600 thermal generating stations, over 100 hydro facilities and 9 nuclear power plants. Total installed capacity is 212 GW, and total distance of the power transmission and distribution network is approximately 2.5 million km. The regional energos operationally retain roughly 135 GW, including about 65 GW of CHP and 30 GW of smaller thermal and hydro plants. Most regional electricity markets are connected by the Russian integrated power grid, which is organized into seven dispatch zones (Northwest, Central, Volga, Urals, N. Caucasus, Siberia and Far East [1]). The entire integrated power grid is dispatched by a Central Dispatch Office in Moscow and RAO EES regional dispatch offices. The system is planned on the basis that each of the seven regions should have adequate capacity to meet its own needs, with the grid linking the zones mainly providing reliability and some peak economies. In fact, connections and flows between regions are estimated at 10% of generated capacity overall, though the figure is higher in some regions. Independent power generators supply about 4% of total generation, generally at industrial locations. Summer demand is about one third lower than winter demand. Daily load patterns are flat owing to the relatively large industrial demand, and morning and evening peaks are nearly equal. These load characteristics are important in relation to optimum supply system and pricing. However, price reform will have a large influence on these load patterns.

In our model we will treat different zones as separate islands. This is not really true, for there is transmission between the regions, as outlined in the chart below. Including this transmission, however, would not drastically change our conclusions, but simply scale them down a bit. For one thing, the transmission capacity, when compared with the region's overall capacity, is not very high:

[1] The Far East grid is not integrated with the others.

Figure 1: Transfer capabilities and regional capacity in Russia



Source: Company data, Incotec

Because of grid limitations, there will be no unified electricity market for the country of Russia in the foreseeable future. Effectively, there will be six merit orders operating in Russia, defined by the existing grid subdivisions. Because there are few transmission lines and few stations in the Far East, a market based on competitive generation will not be feasible there for the foreseeable future; and electricity in that region will continue to be regulated.

Market Architecture.

The architecture of a market comprises the list of component sub-markets together with their types and linkages. Sub-Markets in Russia are the following: day-ahead market, balancing market, ancillary service market and forward market. [1]

[1] For more details see the Model of the Russian Wholesale Market [40].

Market Rules (Design).

Russian wholesale electricity market will operate on the principles of self-scheduling and market clearing. A supply bid is simply an offer to supply energy at any price at or above the bid price, and similarly a demand bid is an offer to take energy at any price at or below the bid price. In Russian case companies may provide from 1 to 25 supply bids for every hour.[1] With this interpretation, the market-clearing price (MCP) is the one that equates supply and demand. No system optimization is involved, and it is each supplier's responsibility to schedule its own plants optimally to provide the energy sold. Settlements are made at the MCP in each market, so a supplier can deviate from its day-ahead schedule by trading the difference in the hour-ahead market or the real-time market. This simplicity hides considerable complexity, however. In the day-ahead market, the price for each hour of delivery the next day is determined independently of the others. No account is taken of intertemporal constraints at the system level. Startup and ramping are chosen by each supplier individually. Similarly, spatial factors such as local generation required by the system operator for grid reliability are ignored in the energy exchange; the system operator obtains assurance that it can call on the requisite resources via long-term contracts. Transmission constraints are ignored in the exchange's initial market clearing. Congestion is alleviated by selecting among offered adjustment bids (incs and decs) in a separate after-market run by the system operator. The system operator absorbs the cost of intra-zonal congestion management conducted in real-time using supplemental incs and decs offered on short notice. Ancillary services are also ignored initially. The system operator conducts separate markets for the various reserve services, but also each exchange has the option to self-provide reserves. From these three aspects omitted from the market clearing it is evident that the design of such exchanges is intended to isolate the energy markets as much as possible

[1] So, generator may provide up to 600 bids per day. That is why it is reasonable for generators to calculate a supply curve; otherwise, recalculating 25 bids for every hour may be very complicated. This is another reason for us to use the SFE.

from the others. The day-ahead markets for transmission adjustments and ancillary services are conducted separately by the system operator after the close of the energy markets. Only the residual energy market for real-time balancing and load following is conducted directly by the system operator.

Timing[1]

During the year: participants may sell energy using bilateral contracts and must inform the System Operator (SO) about those contracts.

Day-ahead (X): players receive demand forecasts, hydropower plants production forecasts, congestion forecasts from the SO for the following day for every hour, and using this information provide their supply bids to the SO.

Day X+1: the SO sets the market-clearing price using supply bids of players and publishes equilibrium quantities and prices in Internet.

Proposed structural changes

In our research we will analyze set up of SMUEK (Middle Volga Interregional Managing Power Company). This is not a usual merger, because none assets of regional energos were placed with SMUEK which performance is regulated by the legislation in force laws stipulating the transfer of the executive powers to the managing company. Thus, director general powers were conveyed to SMUEK: Samaraenergo (16.02.2001), Ulianovskenergo (13.04.2001), Saratovenergo (21.05.2001), Kalmenergo (28.05.2001). Still all above companies remained independent with the assets being left in the holders' ownership. When we started our research intentions of RAO UES about merging regional energos was not clear. However, in March 2002 SMUEK management proposed to merge all SMUEK companies into single one. RAO UES is going to support this plan.

[1] According to the Model of the Russian Wholesale Market [40].

New structure will allow management to coordinate production levels and influence on equilibrium prices.

Unified Energy Systems of Russia also plans to set up Northern Power Management Company to manage the Vologdaenergo, Arkhenergo and Kostromaenergo power companies. Far Eastern Power Management Company will manage Dalnergo and Luchegorsk Fuel and Energy Company. In addition, UES plans to set up Caucasian Power Management Company to manage Ingushenergo, Karachaevo-Cherkesskenergo, Sevkavkazenergo and Kabbalkenergo. Volzhsky Hydroelectric Kaskad has also been set up to manage Volzhsky-based Volzhskaya Hydroelectric Power Plant and Zhigulevsk-based Volzhskaya Hydroelectric Power Plant.

We will also analyze possible entry of new independent power producers (IPPs). Possible candidates for new entry are foreign energy companies and oil companies by using high efficiency combined cycle gas turbines (CCGT) to utilize gas from oil and gas fields, because now they do not have free access to gas pipelines.

METHODOLOGY

To analyze the wholesale electricity market in Russia we will use the **supply function equilibrium** (SFE) model that directly take into account the specific features of electricity markets.

Klemperer and Meyer (1989) modeled an oligopoly facing uncertain demand, and argued that in such an environment firms would prefer to set supply functions, rather than compete in prices (Bertrand competition) or quantities (Cournot competition). They observed that under demand uncertainty - given any hypothesized behavior by other firms (i.e. price or quantity setting) - the residual demand facing each firm is uncertain, and hence each firm has a set of profit maximizing points (price-quantity pairs), one corresponding to each realization of its residual demand. If firms must decide on their strategies in advance of the realization of demand, then they are better off specifying an entire supply curve, rather than a single price or quantity. Green and Newbery (1992) applied this model to the electricity industry reforms in England and Wales (E&W). Green (1996) used a linear version of this model and applied it to the prospective divestitures of generation assets mandated by the regulator of the electricity industry in E&W. Baldick, Grant, and Kahn (2000) offer a generalization of Green's model and extend the application to subsequent changes in the horizontal structure of the electricity market in E&W, beyond those studied by Green. Restructuring in Russia has many features of E&W experience. Recent reforms of the electricity industry around the world have stimulated numerous studies of oligopoly behavior in restructured electricity markets. Papers of this kind have been published reflecting issues in Scandinavia, Spain, New Zealand, and U.S. electricity markets, particularly California.[1] The SFE model formulation at least offers the possibility of developing some insight into the bidding behavior of firms, particularly in markets where they are constrained to bid consistently over an extended period of time. One recent example of this application is the use of the SFE framework by the Market Monitoring Committee of the California Power Exchange (Bohn, Klevorick, and Stalon (1999)).

FORMULATION OF THE BASIC MODEL

In the SFE model, functional forms must be specified for demand, cost, and supply functions.

Demand

A major problem associated with practical use of the SFE model is the representation of demand. The plausibility of price forecasts with these models depends substantially on how the demand curve is specified. A good part of the problem of representing demand involves how the de-

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[1] For Scandinavia, see Andersson and Bergman (1995). For Spain, see Alba *et al* (1999), Ramos *et al* (1998) and Rivier *et al* (1999). For New Zealand, see Read and Scott (1996). In all three of these countries hydro plants plays an important role. For the US, see Borenstein and Bushnell (1998). US markets typically involve network congestion is-

mand curve is “anchored” in price-quantity space. Green and Newberry (1992) use an estimate of pre-competition marginal costs and production to anchor their demand curve. In our research we will follow Green (1996) and will use a demand curve in the form of

$$D(p,t) = N(t) - \gamma p \qquad \textbf{(1)}$$

with N(t) specified as a load curve and a slope parameter γ.

Price elasticity and slope parameter

Green (1996) use parameter 0.5 GW/(£/MWh). This value is considerably higher than what other authors use. Green and Newberry (1992) use parameters 0.1, 0.25, and 0.5 GW/(£/MWh), resulted elasticity at equilibrium: 0.25, 0.4, and 0.64. Bushnell (1998) uses 0.1 GW/(£/MWh). Bunn and Day (1999) use values between 0.01 GW/(£/MWh) and 0.10 GW/(£/MWh).

Filippini (1999) estimated the price elasticity to be 0.30 for residential electricity demand using aggregate data at a city level for 40 Swiss cities over the period 1987 to 1990. The estimated price elasticity for different industrial sub-sectors range from 0.21 to 0.6 in Denmark according to Bjørner and Jensen (2000). Atkinson and Manning (1995) calculated average price elasticity about 0.5 (Minimum 0.06, Maximum 1.06) from studies published between 1975-1993. In Russia the Energy Research Institute of Russian Academy of Sciences (ERI RAS) estimated price elasticity to be 0.16…0.26 [29]. We find that the range of parameters 30…60 MW/($/MWh) bracket the correct value of implied levels of elasticity of market price.

Load duration curve

We will analyze monthly demand using data from Goskomstat (1996-1999). The load curve in Middle Volga is very similar to the whole Russia and will use average load curve as a proxy of Middle Volga load curve adjusted by the region specific factors (average capacity utilization, net-

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sues. Network congestion is treated in an oligopoly context by Hogan (1995) and by Borenstein, Bushnell and Stoft (1999).

work losses). Average capacity utilization in Middle Volga is about 42,2% and network losses are very high - 15%.

In Russia information about hourly consumption for different consumption classes is unavailable. However, we will use available data about consumption in Russia and SDG&E Static Load Profiles 1999.[1] Using this data we will estimate load duration curve N(t) for every consumption class, e.g. residential. In Russia, the price structure subsidizes residential relative to commercial industrial users. We believe, that after reform the pricing of electricity consumption will be more close to marginal cost of consumed energy. After that we will find hourly demand using consumption structure for analyzed region. This will allow us to find effective price structure in the region and compare this structure with the current one.

Table 1: Structure of electricity consumption in Russia, Middle Volga and San Diego

	San Diego	RAO UES	Middle Volga
Industry	55,8%	75,5%	74,1%
Agricultural	1,0%	4,3%	2,20%
Residential	43,2%	20,2%	23,7%

Using data from Table 1 we will adjust load duration curve in San Diego for Russian consumption structure.

Marginal Costs

Next we consider the marginal cost as a function of production. There is a range of possible functional forms. The SFE models reported in the literature typically assume that the bidders' marginal cost functions have zero intercept, or, equivalently, assume that all have a common intercept.

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[1] For more details see Appendix B. Load Profiling.

This makes the SFE easier to find. Occasionally authors attempt to defend the plausibility of this assumption. We argue that, at least for electricity, this assumption is neither plausible nor practically useful. We will use an asymmetric affine function with non-zero intercept. If the marginal costs curves are equal at full production, then assuming that the marginal costs pass through zero will over-estimate profits compared to the true function. The affine case will typically under-estimate profits. The line through zero is likely to be particularly unrealistic when the actual supply of a firm is from the low end of its capacity. This form results in an affine marginal cost function for each firm:

$$\forall i, \forall q_i \geq 0, \quad dC_i / dq_i(q_i) = c_i q_i + a_i \qquad \textbf{(2)}$$

with $c_i > 0$ for each firm i for strictly convex costs. We will use cost estimates derived from published thermal efficiencies and fuel prices. After that we will approximate piecewise cost function by affine function.

Supply

Finally, consider the supply as a function of price. Typical applications use a form for the supply function that is similar to the assumed form of the marginal cost function.

For example, Turnbull (1983) analyzes an asymmetric two-firm model with linear demand, affine marginal costs, and affine supply functions. The resulting conditions for the SFE are straightforward to solve. Green and Newbery (1992) generalize the linear demand and linear marginal cost asymmetric two firm model by analyzing strategic firms having quadratic marginal costs. For the duopoly structure examined, Green and Newbery (1992) report results primarily for the case of symmetric strategic firms. As the structure of the electricity industry in E&W has changed, Baldick, Grant, and Kahn (2000) drop the symmetry and the duopoly assumption and improve numerical fit of the SFE model. The asymmetric duopoly case is also solved by Green and Newbery (1992) and by Laussel (1992). For practical applications, the asymmetric case is more interesting. This motivates the use of the linear model for the asymmetric, multiple strategic firm industry we consider. We assume that the market rules specify that the supply function of each firm is asymmetric and affine; that is, of the form:

$$\forall i, q_i(p) = \beta_i (p - \alpha_i). \qquad \textbf{(3)}$$

In order to take into account low demand and price levels and maximum capacity constraints we will follow Baldick, Grant, and Kahn (2000) and assume that the bid rules allow for piecewise affine, non-decreasing bid supply functions. We can construct a candidate SFE in piecewise affine supply functions by piecing together several supply functions. In each piece we will evaluate the slope of the supply functions of the firms that are actually generating. So long as the resulting composite supply functions are all non-decreasing then the candidate is truly the SFE.

The Game

We assume that each firm submits a linear supply schedule. The strategy for firm *i* is formally α_i, β_i such that supply function $q_i(p) = \beta_i(p - \alpha_i)$ map price into a level of output independent of time, *t*.[1] We look for only noncooperative Nash equilibrium of the spot market as a single-shot game.[1] It could be argued that these conditions will lead to a collusive equilibrium in the repeated game. However, we do not study this outcome. The possibility of collusion may worsen an already unattractive situation.

Demand at any moment during the day is deterministic and is given by $D(p) = N(t) - \gamma p$. There are *n* firms with marginal costs $\forall i, \forall q_i \geq 0, \ \frac{dC_i}{dq_i}(q_i) = c_i q_i + a_i$. Marginal costs and de-

[1] In practice, each firm's bid schedule is a step function, rather than a linear function. It is an open question whether the bidding strategies of the firm will differ significantly if they are forced to provide a step function, or whether they are allowed to provide smooth schedule.

mand (c_i , a_i , γ, $N(t)$) are common knowledge. The net demand facing firm i at moment t when other firms $j =1\ldots n, j\neq i$ have supply schedule q_i is $D(p)-\sum_{j\neq i} q_j(p)$.

Each firm submits its supply function to the System Operator (SO) simultaneously (the day before), and the SO then determines the spot price and each firm's supply by solving for the price-output pair that equates supply to demand at each moment. That is, at each moment t the SO announces the lowest price such that $D(p(t)) = \sum_{i=1\ldots n} q_i(p(t))$, provided that such price exists. If such a price does not exist, the firms are paid zero. Supply function $q_i(p)=\beta_i(p-\alpha_i)$ at any t, describes profit-maximizing price-output pairs. Firms choose α_i, β_i such that profit-maximizing solution can be found by maximizing profit $\pi_i(p)=pq_i - C_i(q_i)$ with respect to p given q_j $j =1\ldots n,\ j\neq i$:

$$\forall i \quad \pi_i(p) = p[D(p)-\sum_{j\neq i} q_j(p)] - C_i[D(p)-\sum_{j\neq i} q_j(p)]$$

$$F.O.C. \qquad \forall i \quad D(p)-\sum_{j\neq i} q_j(p) - \left\{\left[p-\tfrac{dC_i}{dq_i}\left(q_i(p)\right)\right]\left(-\tfrac{dD}{dp}+\sum_{j\neq i}\tfrac{dq_j(p)}{dp}\right)\right\}=0$$

$$\forall i \quad q_i = \left\{\left[p-\tfrac{dC_i}{dq_i}\left(q_i(p)\right)\right]\left(-\tfrac{dD}{dp}+\sum_{j\neq i}\frac{dq_j(p)}{dp}\right)\right\}$$

$$\forall i \quad \beta_i(p-\alpha_i) = \left\{\left(p-c_i\beta_i(p-\alpha_i)-a_i\right)\left(\gamma+\sum_{j\neq i}\beta_j\right)\right\}$$

Solving these equations we will find the equilibrium for our model. Changes in market structure will lead to change of firms (decision-makers) number and the forms of their marginal costs.

Timing of the moves

Day X-1: players provide their supply function to the SO simultaneously.

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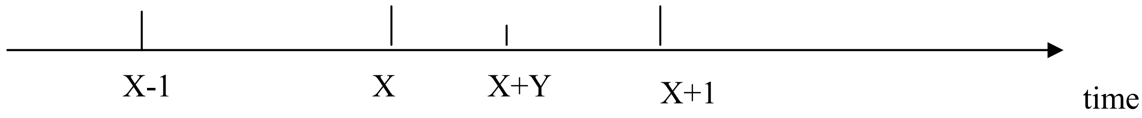
[1] Since the bidding process is repeated daily, we do not feel that there would be any "learning" problems in reach-

Day X+Y hours: the SO sets the market clearing price for hour Y using supply functions of players and demand for hour Y.

Day X+1: players receive their profits.



ing equilibrium.

GENERAL APPROACH TO SFE MODEL.

The affine SFE provides one SFE for the asymmetric affine marginal cost uncapacitated case. Baldick and Hogan (2001) showed that it is generally very difficult to find solutions of SFE model that are non-decreasing over all realized prices except in very special cases, namely:

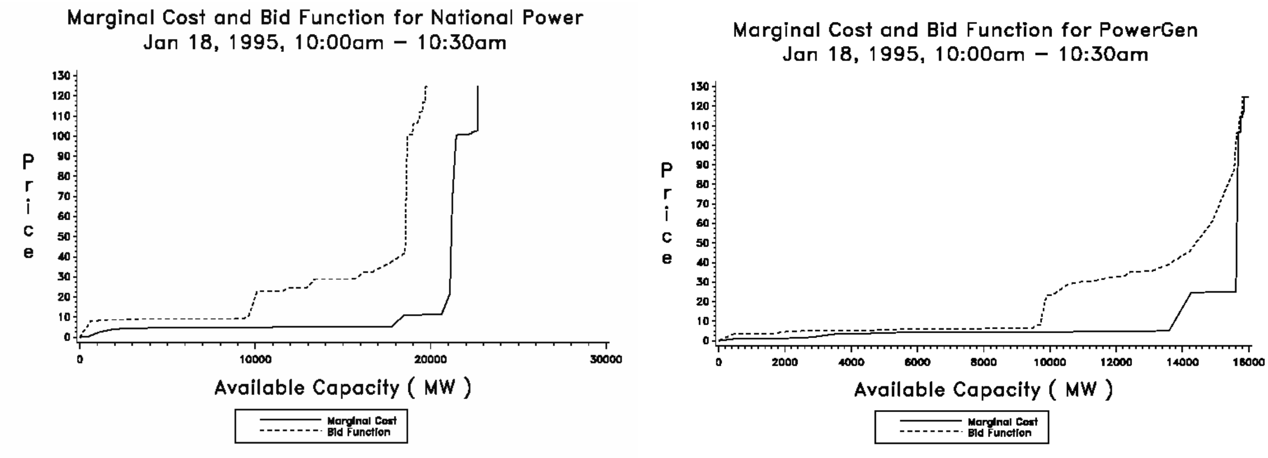
1. if the cost functions are the same for each firm, as explored by Klemperer and Meyer (1989) and Green and Newbery (1992),
2. if the marginal costs are affine and there are no capacity constraints so that there are linear or affine solutions to (9), which was explored in Green (1996), Rudkevich (1999), Baldick, Grant, and Kahn (2000), or
3. if the load factor over the time horizon is very close to 100%.

However, Wolak and Patrick (1997) showed that capacity constraints play an important role in empirical examples.

They constructed their estimate of the marginal cost function based on supply schedules for National Power and PowerGen by the following procedure:

"For each genset owned by these two firms we first compute the maximum amount of actual availability declared within any load period during the calendar year 1995. We think of this as a lower bound on maximum capacity available from each genset. For each genset we then compute the minimum bid price offered for that genset in any load period when this maximum availability is offered during the year. We can think of this minimum genset bid as an upper bound on the marginal cost of that genset. Ordering these maximum genset availabilities from the lowest to highest minimum price, and then aggregating the total amount offered at less than or equal to each price yields the solid line given in each figure. We believe this process yields an upper bound on the true marginal cost function. "

Figure 2: Wolak and Patrick marginal cost function estimates



Thus, it is more reasonable to analyze solution in affine capacity constrained case. Thus we will introduce a more general framework for SFE model. This includes piecewise-linear supply curves, capacity constraints, price caps and floors. The model is close to described above. One possible description of the model you can find in Appendix D. The solution can be only numerical, so we use different software and optimization methods from this software to calculate results. The model was implemented using Visual Basic, Excel Optimization Toolbox and Matlab.

EMPIRICAL EXAMPLE

In our empirical example we analyzed proposed structural changes in the Middle-Volga Region.

Table 2: Main players in Middle Volga

	Capacity, MW	Production in 1995, GWh	Number of power plants
Tatenergo	5829	20581	8
Samaraenergo	2675	12051	7
Chuvashenergo	1400	4000	3
Saratovenergo	1246	4044	5
Ulianovskenergo	768	2540	2
Penzaenergo	375	1338	3
Mordovenergo	340	934	3
Marienergo	80	464	1

We analyze the effect of merging of Samaraenergo, Saratovenergo and Ulianovskenergo into one company. After that we will analyze the entry of new independent power producers (IPPs) 1600MW.

Marginal cost functions $\forall i, \forall q_i \geq 0, \quad dC_i / dq_i(q_i) = c_i q_i + a_i$

Stage1:

In this case we analyze situation as it is. Thus, the result will serve as a base for comparison of possible changes.

	a	c	Capacity
Tatenergo	4,69389	0,00213	7003,0
Chuvashenergo	10,08853	0,00155	1370,0
Samaraenergo	12,83857	0,00241	3494,7
Saratovenergo	11,81821	0,00459	1502,0
Ulianovskenergo	14,21815	0,00121	862,0

Stage2:

In this case Samaraenergo, Saratovenergo and Ulianovskenergo are merged into single company.

	a	c	Capacity
Tatenergo	4,69389	0,00213	7003,0
Chuvashenergo	10,08853	0,00155	1370,0
SMUEK	12,75031	0,00127	5858,7

Stage 3:

Stage 4:

In this situation we will analyze effect of entry of a new player (Independent Power Producer).

	a	c	Capacity
Tatenergo	4,69389	0,00213	7003,0
Chuvashenergo	10,08853	0,00155	1370,0
IPP	5,00000	0,00100	1500,0
SMUEK	12,75031	0,00127	5338,7

In this situation we will analyze effect of entry of a new player in the base case. This will allow us to analyze effect of merger on entry incentive.

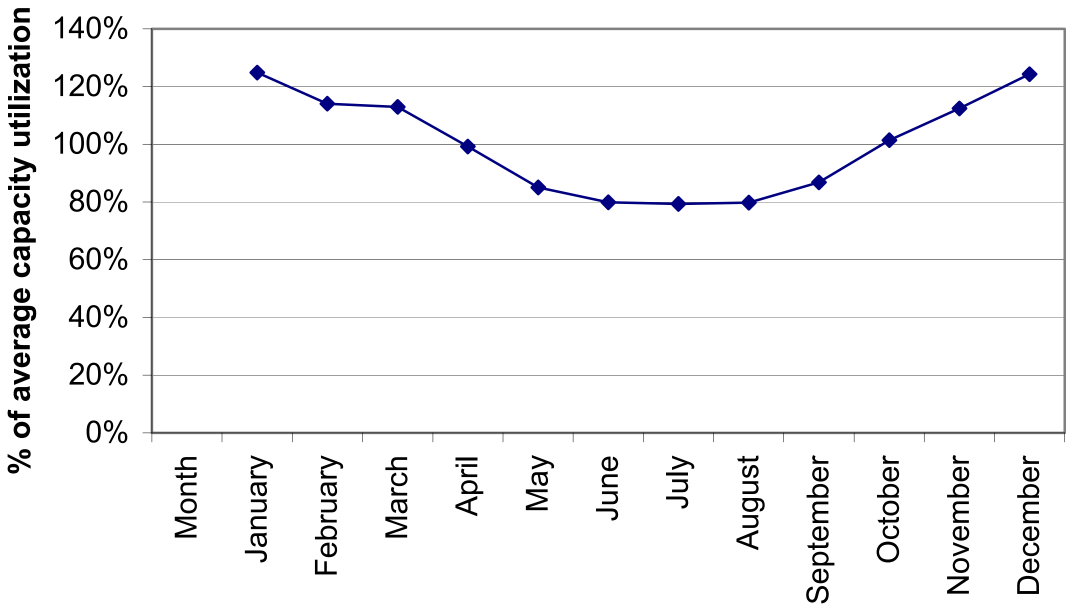
	a	c	Capacity
Tatenergo	4,69389	0,00213	7003,0
Chuvashenergo	10,08853	0,00155	1370,0
Samaraenergo	12,83857	0,00241	3494,7
IPP	5,00000	0,00100	1500,0
Saratovenergo	11,81821	0,00459	1502,0
Ulianovskenergo	14,21815	0,00121	862,0

Demand

$$D(p,t) = N(t) - \gamma p$$

As we previously found slope parameters (γ): 30, 45, and 60 may be used to analyze restructuring in Middle Volga.

Figure 3: Average Load Curve, Russia (1996-1999) (Average capacity utilization=42,2%)



Solution

In our solution of the SFE model we will follow Baldick, Grant, and Kahn (2000).

$$\forall i, \quad \beta_i = (1 - c_i \beta_i)\{\gamma + \sum_{j \neq i} \beta_j\} \qquad \forall i, \quad \alpha_i = a_i.$$

Case 1 ($\gamma = 30$):

Stage 1:

	alpha	beta
Tatenergo	4,69	358,00
Chuvashenergo	10,09	443,64
Samaraenergo	12,84	326,75
Saratovenergo	11,82	192,70
Ulianovskenergo	14,22	513,69

Stage 2:

	alpha	beta
Tatenergo	4,69	282,67
Chuvashenergo	10,09	327,51
SMUEK	12,75	352,72

Stage 3:

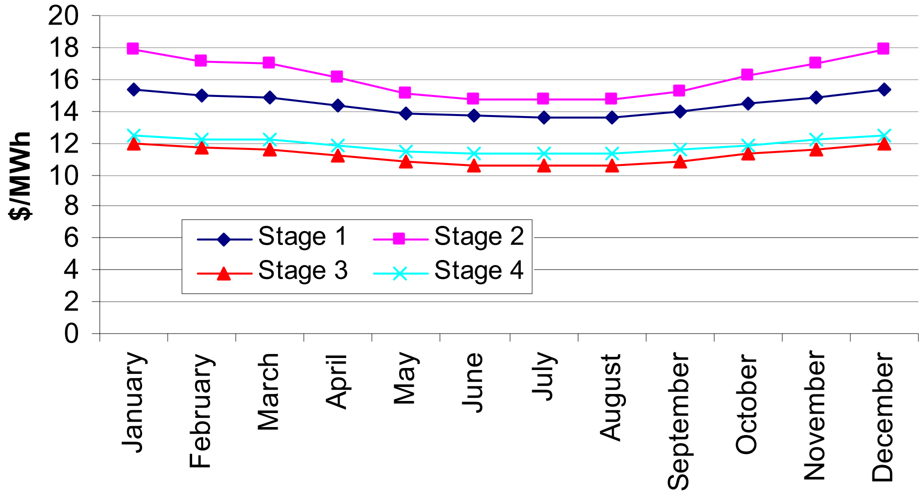
	alpha	beta
Tatenergo	8,94	116,72
Chuvashenergo	6,72	108,13
IPP	9,52	53,82
SMUEK	6,00	108,23

Stage 4:

	alpha	beta
Tatenergo	4,69	391,60
Chuvashenergo	10,09	501,24
Samaraenergo	12,84	353,67
IPP	5,00	674,85
Saratovenergo	11,82	200,66
Ulianovskenergo	14,22	598,36

Using these numbers we can find a solution for the SFE model. On the graph we can see price variations during the year in case of slope parameter equal to 30.

Figure 4: Affine-linear SFE solution (slope parameter=30)



	Stage 1	Stage 2	Stage 3	Stage 4
Weighted Average Prices, $/MWh	14,50	16,34	11,31	11,92

We received interesting result, that merger does not change considerably entry incentives. Entry of IPP with and without merger lead to prices, which differ only by 5% compared to 13% difference in pre-entry situation with and without merger and 44% price decrease after entry of IPP after merger.

Rational IPP would predict such results, so merger will provide quiet small additional incentive to entry. However, if IPP believe that prices will stay on the same level as before entry, merger and resulted higher prices can provide additional incentive for new entrants.

Effect of changes in slope parameter

Now we will analyze how results will change due to variations of slope parameter.

Figure 5: Affine-linear SFE solution (slope parameter=45)

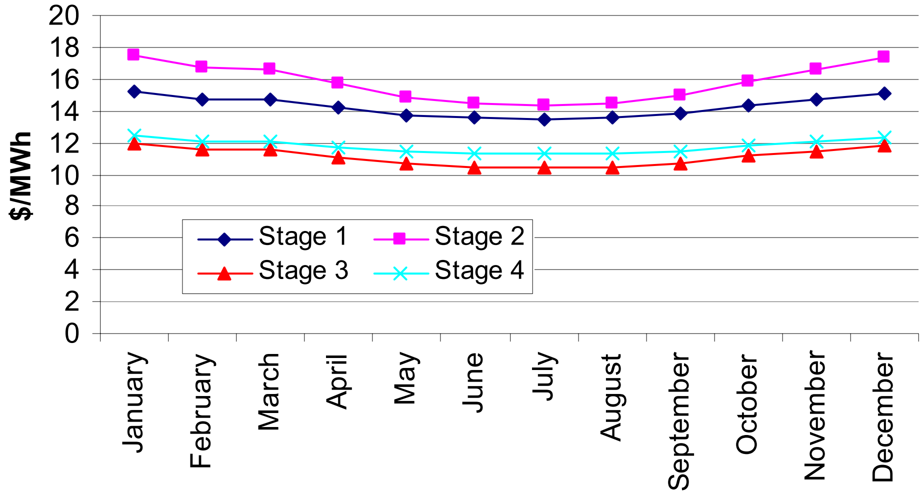
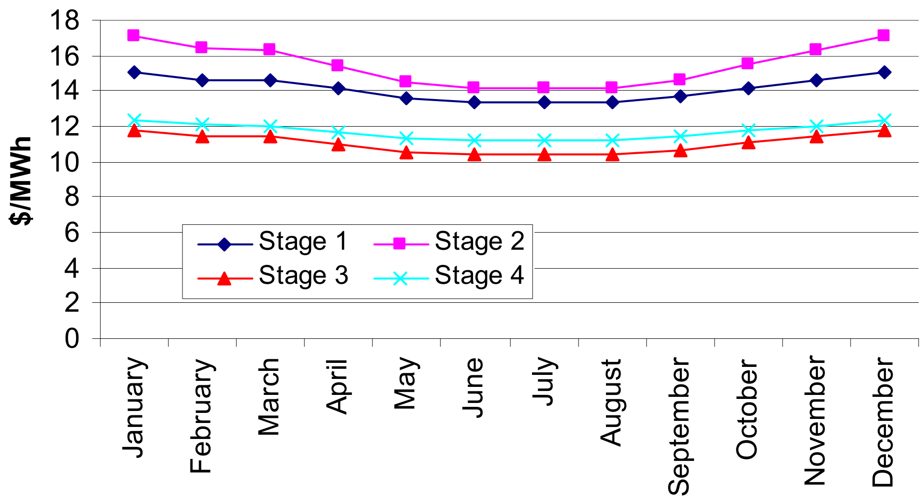


Figure 6: Affine-linear SFE solution (slope parameter=60)



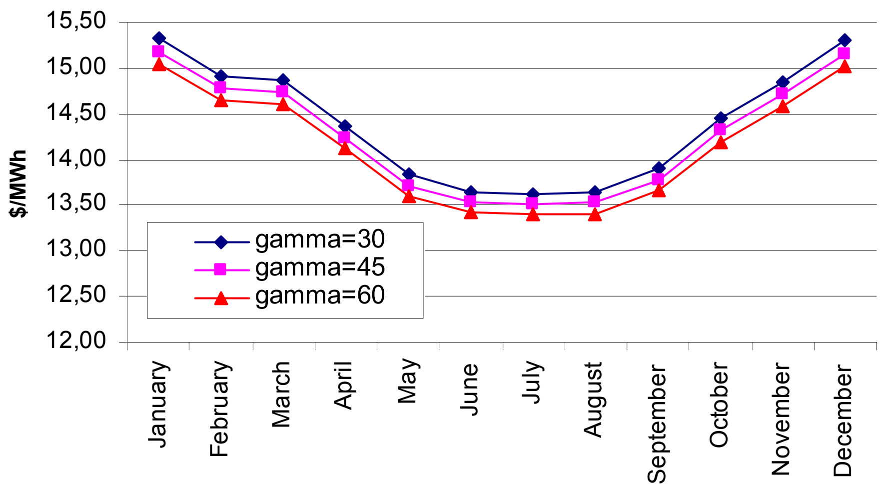
We can see that slope parameter does not considerably affect equilibrium prices. We weighted price curve by load and found that in case of gamma increase from 30 to 60 price changes only by 2%, compared to 13% price variation along our load curve.

Table 3: Effect of changes in gamma on price for Stage 1.

	gamma=30	gamma=45	gamma=60
Load Weighted Average Prices, $/MWh	14,50	14,36	14,24

We can also see that changes in slope parameter cause small changes in prices on the graph.

Figure 7: Affine-linear SFE. Effect of changes in slope parameter.

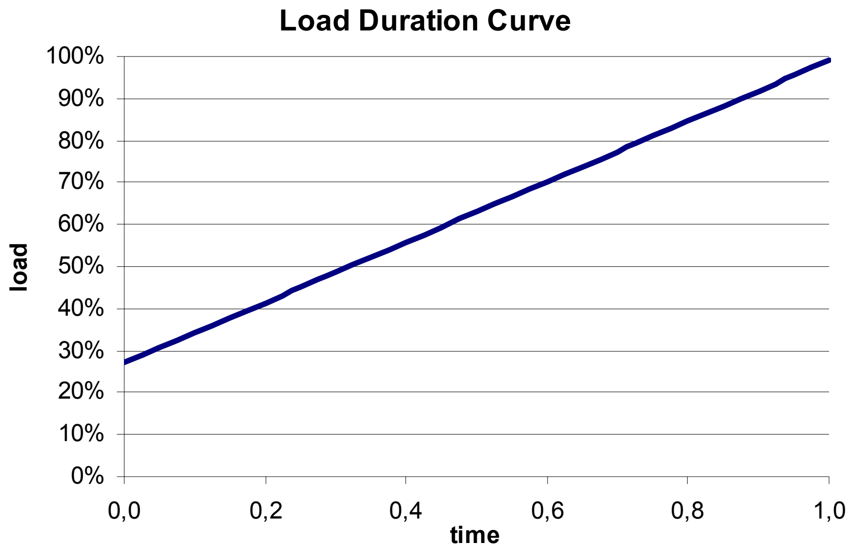


However, in this model capacity constraints are not taken into account. Practical experience shows that most cases of market power on power markets are result of ability of large electricity companies to exhaust competitor's capacity and exploit residual demand.

Capacitated SFE

To handle capacity constraints we will use capacitated SFE model and iterative approach. Now our model is more sophisticated, so we can analyze more extreme cases. To analyze all possible variants we will use specific load-duration curve L=0,27+0,72t.

Figure 8: Load Duration Curve for general SFE.



We will use demand slope at level γ =30 and will analyze effect of merger. As a starting point for iterations we will use results from previous chapter. Below we can find the results of calculations.

Figure 9: Price variations. (Stage 2. No price caps).

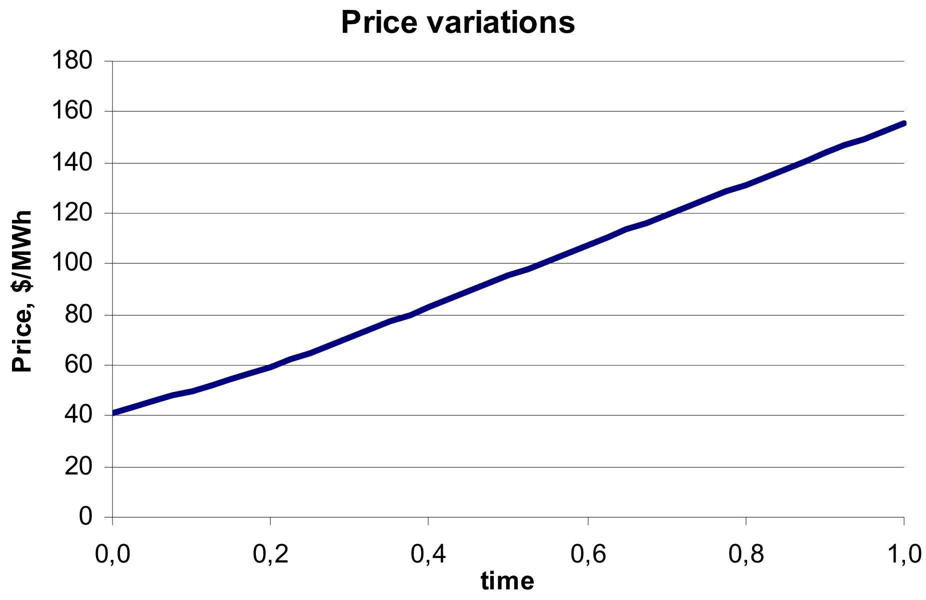


Figure 10: Supply curves. (Stage 2. No price caps).

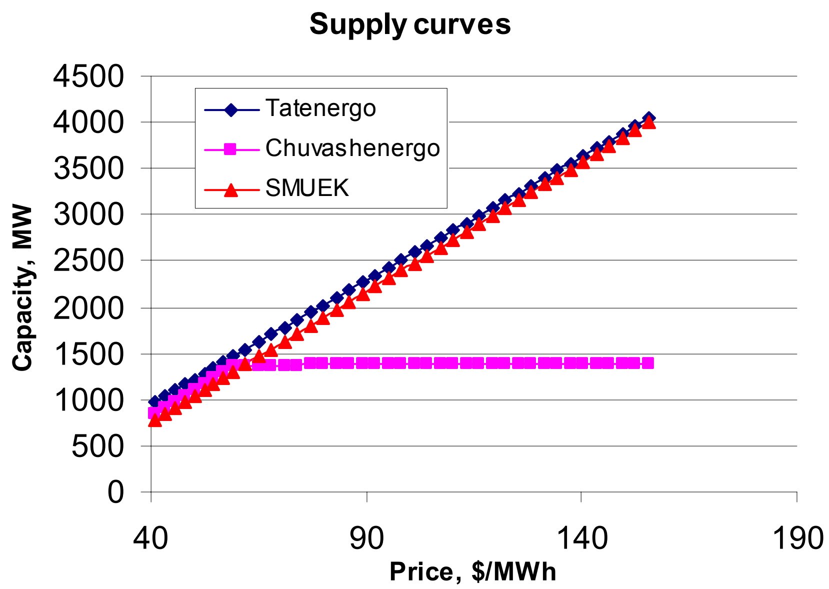


Figure 11: Price variations. (Stage 1. No price caps).

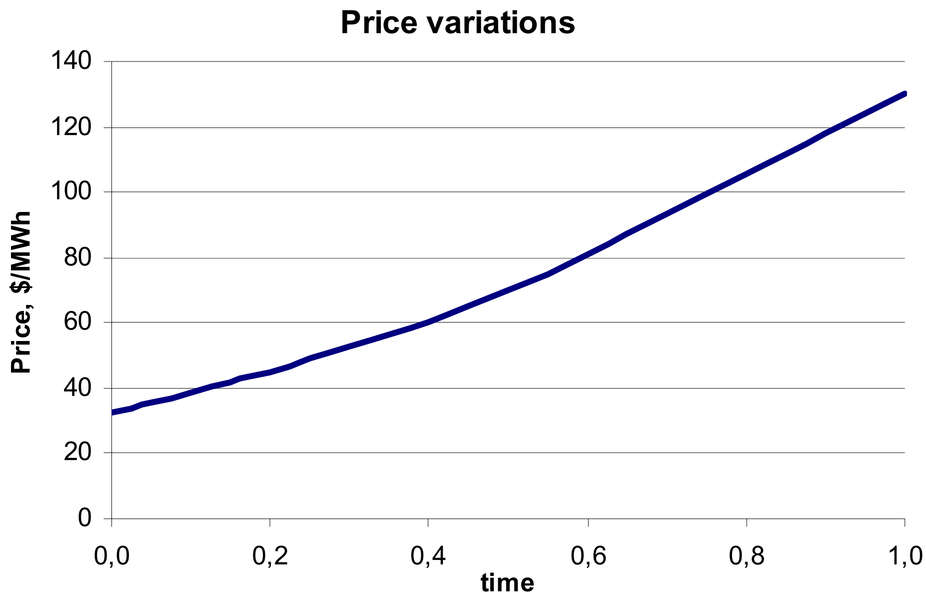
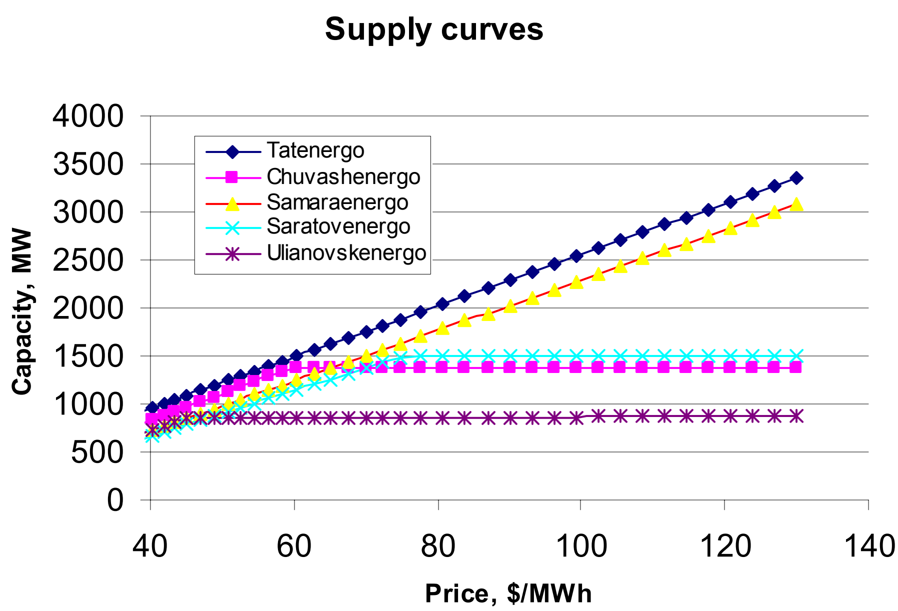


Figure 12: Supply curves. (Stage 1. No price caps).



We found that load weighted average prices increased as a result of merger by 27% is quiet similar to incapacitated model (28%). Though, we cannot compare directly price levels in our models because of the difference in load duration curves, we can see that price level in capacitated model is much higher than in incapacitated model. This is result of specific characteristics of electricity markets. Low demand will lead to equilibrium prices, which are close to marginal costs, but increase of demand will lead to substantial higher prices.

Figure 13: Low demand

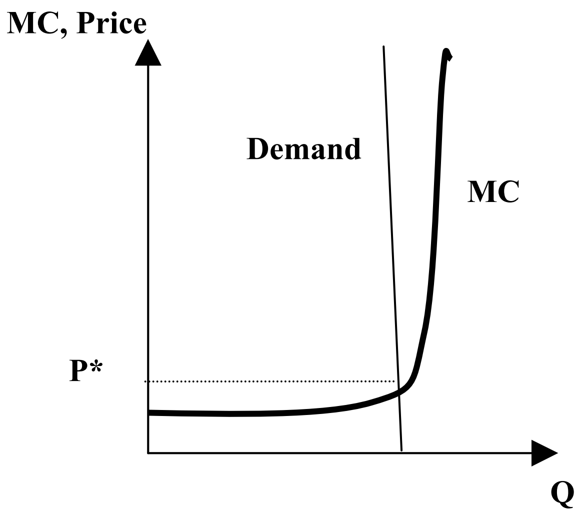
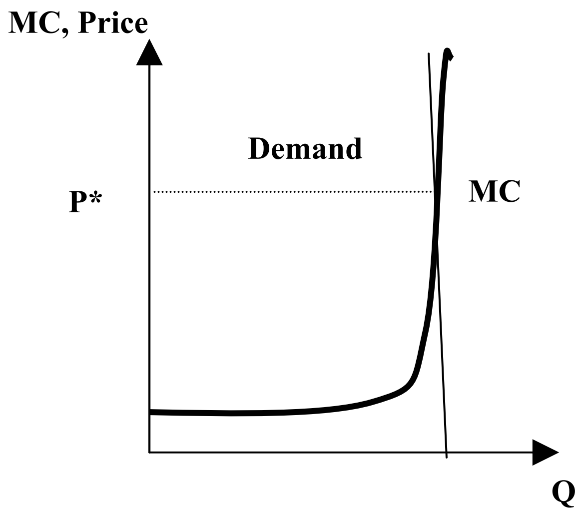
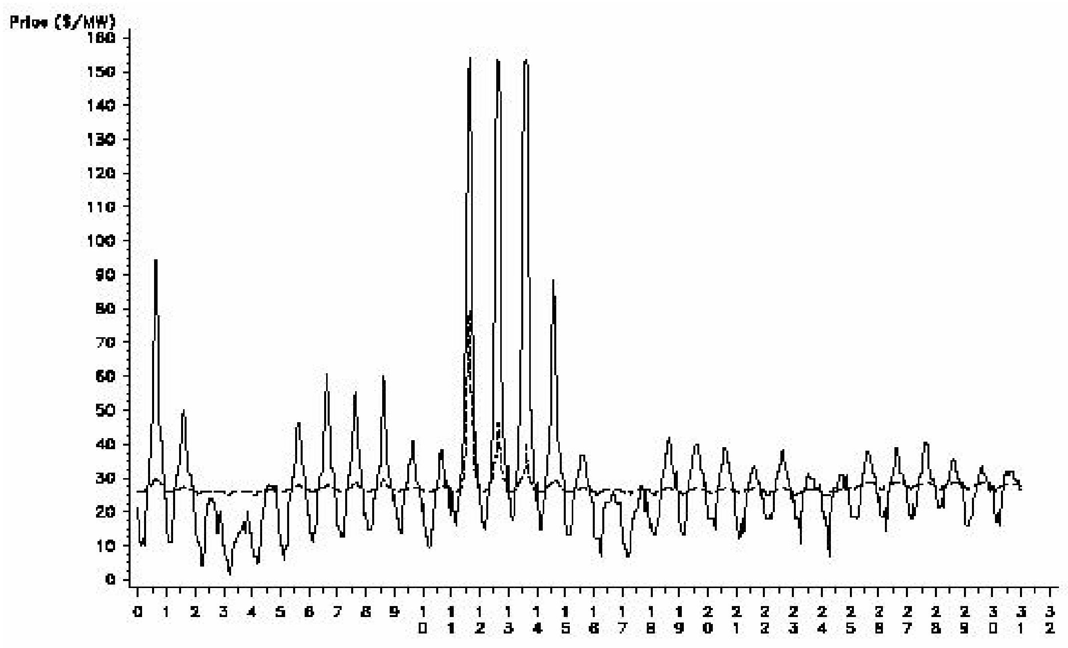


Figure 14: High demand



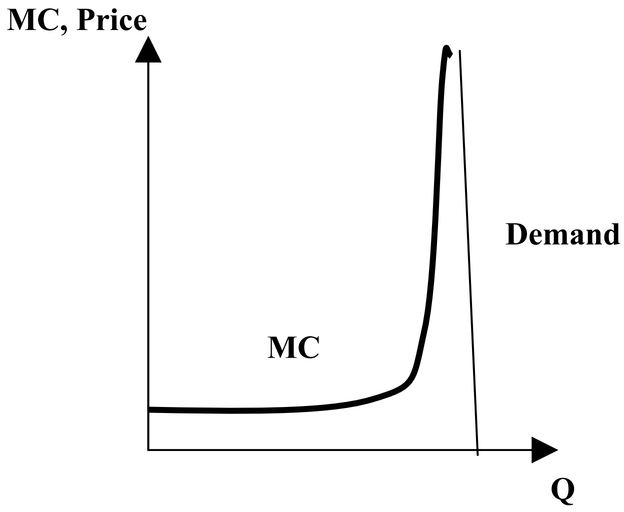
The equilibrium prices will be very volatile and will change rapidly according to demand fluctuations.

Figure 15: California PX Prices and predicted MC: January 1999



Rapid demand increase may cause the market failure. Three conditions are necessary for failure: (1) inelastic demand, (2) inelastic supply, and (3) volatile demand. Given the proper realization of these conditions, imagine starting with too much generating capacity. As capacity decreases toward an equilibrium level, short-run profit will increase, but before it becomes great enough to cover fixed costs, the supply and demand curve will fail to intersect.

Figure 16: Market failure



This is market failure. Price is pushed toward infinity, but even an infinite price cannot clear the market.

Current power markets probably satisfy the conditions required for this failure, that is why price caps should be introduced.

Price Caps regulations

Price caps are widely used around the world. FERC in USA approved price limits of $750, $500 and $250/MWh for California between 1998 and August 2001. In the summer of 2000 it reduced the NY ISO's limit from its previously approved level of $10,000 to $1,000/MWh bringing it in line with PJM's limit. A year later it limited prices indirectly in the West to roughly $100/MWh. In between it suggested that what Western markets really needed was no price limit at all. The Australians tell us prices must be capped at the value of lost load, which they put at between $15,000 and $25,000/MWh AU. The new electricity trading arrangement in England allows much higher prices and promptly set a record of over $50,000/MWh.

However, price caps regulation is ambiguous. As California's wholesale power prices rose rapidly in the spring of 2000, the state Independent System Operator (ISO) was quick to impose a price cap. As a result, amount of power supplied to the state dropped off as suppliers pursued more lucrative opportunities out-of-state. Because consumer prices were not affected (as a result of retail price cap), consumers did not reduce demand, and acute scarcity turned into shortages. The situation rapidly grew untenable, with ISO staff spending more time trying to hustle up power supplies than running the grid. As supplies continued to fall, the ISO had to lift the caps to head off blackouts. Contrast this unfolding of events with the previous "worst-case scenario" of the price spikes in the Midwest in the summer of 1998: price caps were not imposed, market prices attracted both power and investment to the region, and now new power plants are being built. The price spike problem in the Midwest has not recurred.

Now we will introduce price cap at the level p=80 $/MWh and will find the effect on our capacitated model.

Figure 17: Price variations. (Stage 2. Price cap at level 80 $/MWh).

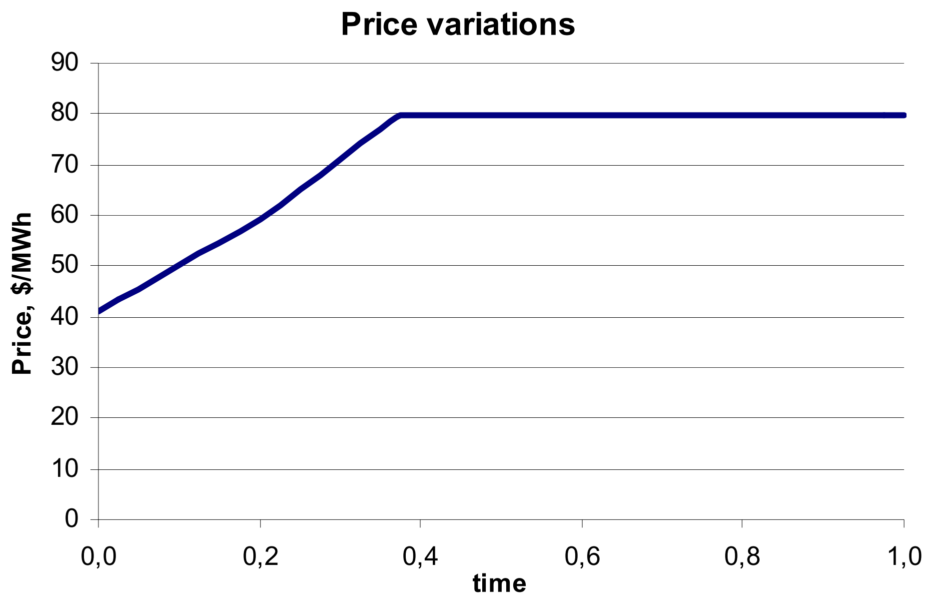


Figure 18: Supply curves. (Stage 2. Price cap at level 80 $/MWh).

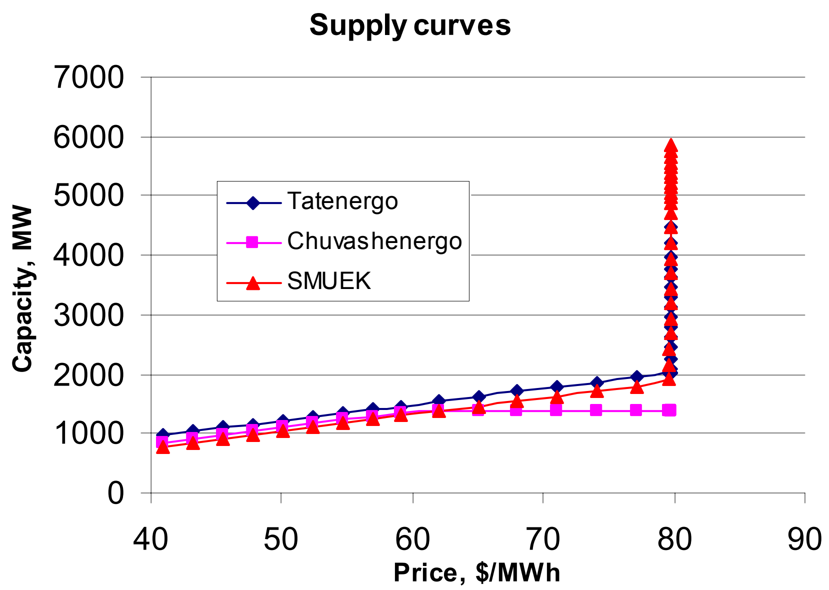


Figure 19: Price variations. (Stage 1. Price cap at level 80 $/MWh).

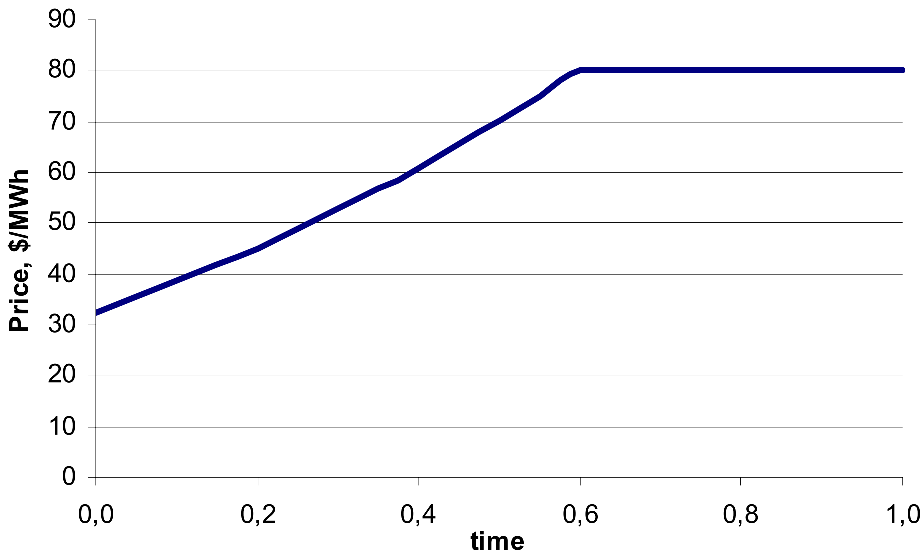
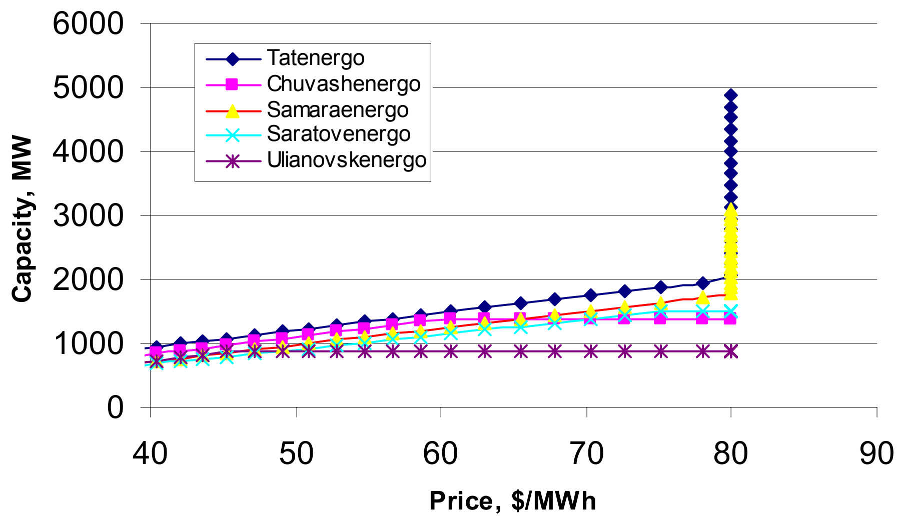


Figure 20: Supply curves. (Stage 1. Price cap at level 80 $/MWh).



We found that in this model introduction of price caps may lead to situation when producers for a long period sell energy at regulated prices. Thus, introduction of low price caps may result: reduced supply, less conservation, higher off-peak prices, longer-term distortions of investment and resource consuming opportunistic behavior in the market.

Analysis of effective prices for different industries.

Now we will analyze prices for different consumers classes. Consumption during the day may vary greatly during the year and during the week. On weekends consumption of industrial sectors decreases and consumption of residential sector rises. Fundamental factors for price variations during the day are very similar for different countries and regions and depend from geographic location, temperature and sunshine duration. However, average load for different regions have less difference than variations of daily load during the year. So, using adjusted USA data for Russia will provide some useful insights. The solution process is the same as in previous paragraph.

Figure 21: Hourly Load Duration Curve, San Diego.

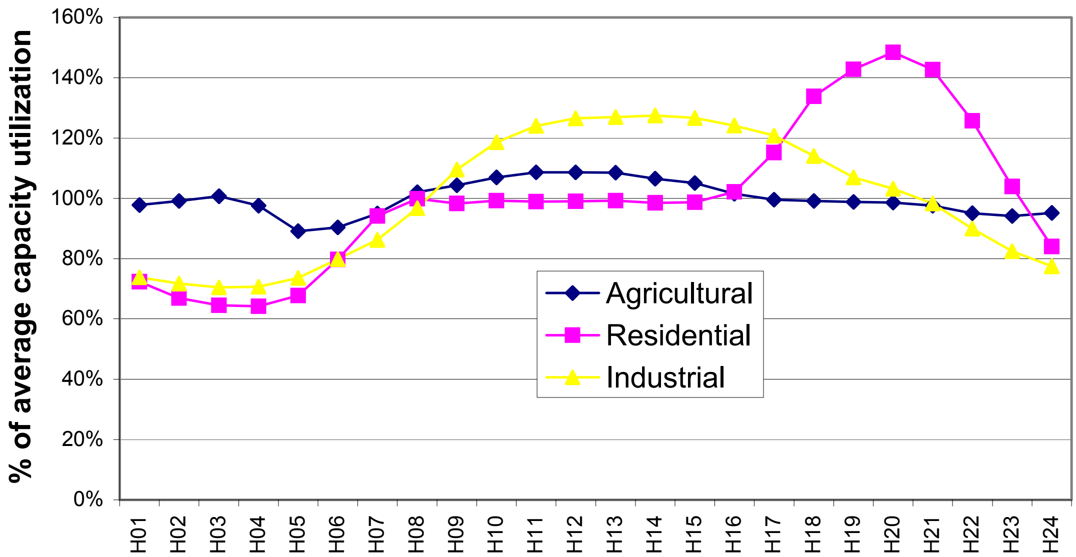


Figure 22: Load Duration Curve

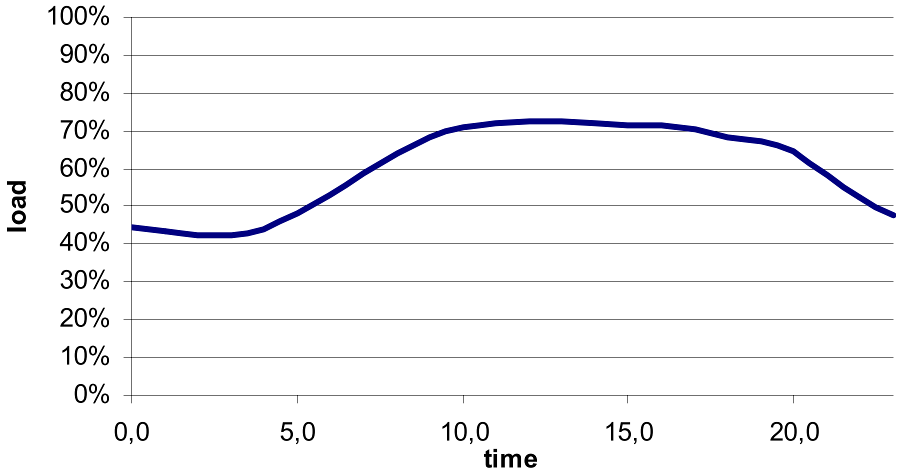
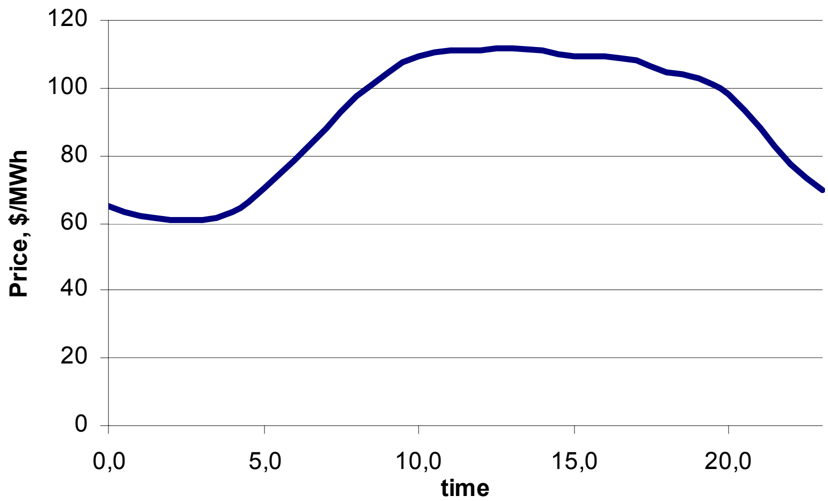
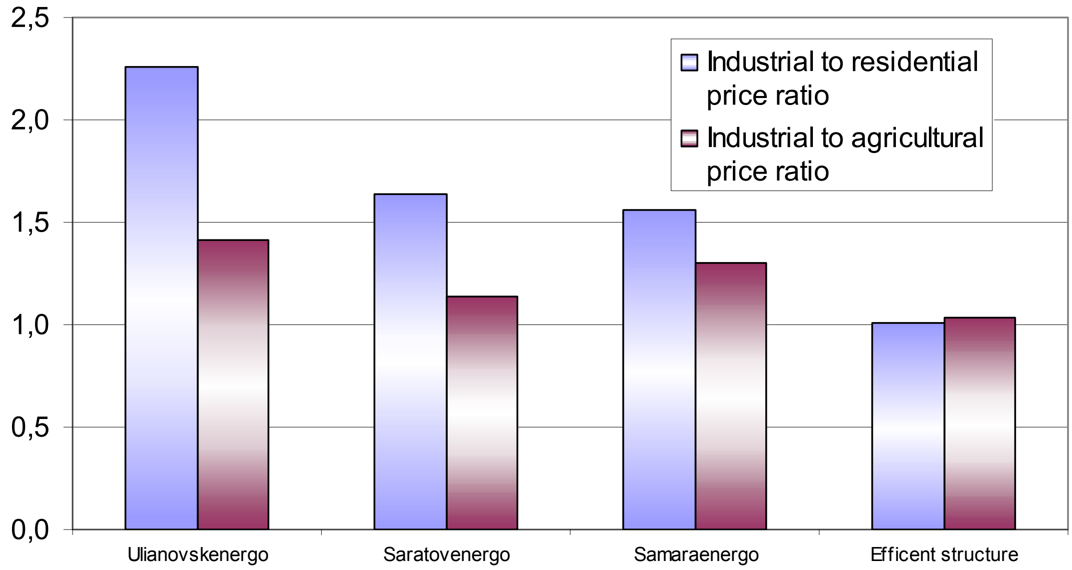


Figure 23: Daily prices



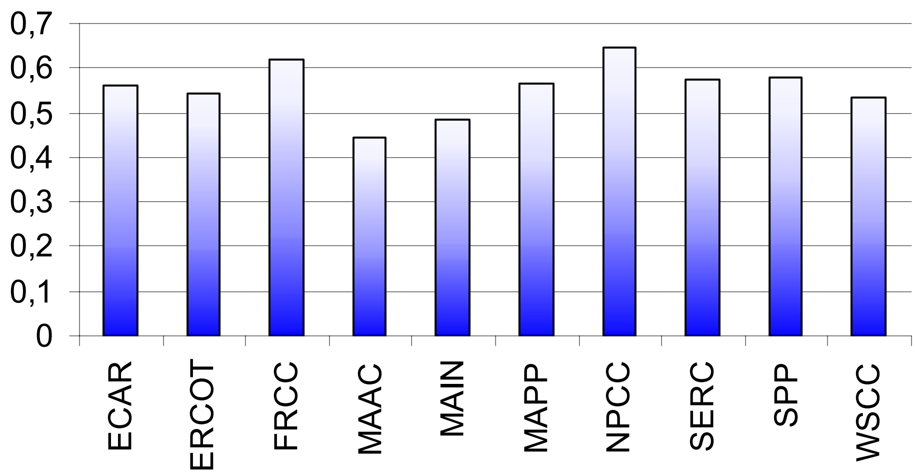
	Agricultural	*Residential*	*Industrial*
Load Weighted Average Prices, $/MWh	91,2	93,7	94,5

Figure 24: Price structure for different classes



We can see that price structure in Middle Volga is far for effective. We received that in effective price structure prices for industrial and residential consumers do not differ very much (less than 1%). This is a result of large share of industrial consumers in whole consumption. In developed countries prices for industrial consumers are smaller than for residential users.

Figure 25: Industrial to residential price ratio (North American Electric Reliability Council)



Industrial consumers have more market power and may have direct access to the wholesale market and use competition between generating companies to receive more favorable prices. Another reason is difference distributional costs. Residential consumers require more meters and billing operations than industrial users. According to our estimates tariffs for industrial and residential consumers should be one percent high plus the difference in distributional costs. Abolition of cross-subsidization will increase efficiency of electricity sector.

POLICY CONCLUSION

Restructuring of electricity sector in Russia may cause drastic price changes. Network constraints in Russia will lead to formation of several nearly independent energy zones. During the restructuring process Government should take into account market power also in energy zones, not only in whole Russia. Otherwise, some energy companies will exploit the constraints on the grid's transmission capacity, since their market power in those regional submarkets is considerably greater than in the country as a whole. In short-term this may lead to substantial price rise. However, in long-term the situation is ambiguous. To improve situation in long-term we should consider following policies.

At the federal level:

Create incentives to improve the transmission grid. Wholesale electricity competition is constrained by the inability of the national grid to efficiently manage power flows that the market demands in real time, and to accommodate longer-term shifts in supply and demand. This is fundamentally an interregional issue, and the federal government must move more quickly to hammer out acceptable policies governing transmission assets, access, and investment that both ensure reliability and provide investors in new transmission capacity with sufficient financial returns and regulatory certainty.

Do not hinder generation capacity markets. While the needs and issues of electricity generation cannot drive the entire nation's energy and environmental policies, there should be accommodation for adding new generation capacity. Facilitating new generation capacity will speed the replacement of old, dirty, and inefficient plants with new, cleaner, efficient plants—resulting in more power from less fuel and less emissions.

Create a plan for phasing out retail price caps. First, move from "cost plus" to price caps regulations. Second, gradually but predictably raise the price caps. Convene a working group to create an initial schedule and revise the schedule periodically as market conditions change.

Next, tie rate cap increases to milestones in accomplishing other policy changes that increase competition and customer choice in the market and reduce utilities' market power. If other policy changes are successful in allowing market entry and new competitive choices for consumers as well as increased electricity supply, the timetable to remove price caps can be moved up.

Meanwhile, implement a system to guard against exercise of vertical and horizontal market power. Until consumers have options in the face of high prices or bad service from utilities, regulatory oversight is necessary.

Finally, encourage utilities to implement real-time pricing and metering so that consumers can adjust their use of electricity as prices change. Implementing real-time pricing and metering can also justify accelerating the schedule for removing price caps.

Free the utilities to purchase power competitively. A spot market is a necessary component of the overall electricity market. But centralized mandatory pools bring to the market perverse incentives and rigidities that create distortions and an inability to adapt to changing market conditions. Encourage a voluntary, independent competitive exchange and develop bidding rules that attract both buyers and sellers. At the same time, the utilities need to add forward contracts to their portfolios to hedge against future wholesale power price fluctuations.

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APPENDIX A. MARGINAL COSTS.

To calculate marginal costs we will use marginal consumption of fuel and the following assumptions about fuel prices. We used the following information about 830 power plants from Incotec (1999) (Printed Edition): disposable capacity, electricity production, thermal energy production, marginal use of fuel in electricity production, marginal use of fuel in thermal energy production, structure of used fuel, depreciation of capital.

Fuel prices: 50% of Western European levels (defined as the average price during the past 20 years), except for fuel oil:

- **Gas**: $40/fuel equivalent tonne (185% increase from 1999)

The government has indicated that gas prices are to be allowed to increase some 2-fold over the coming two years, from today's $17 per 1000 cu m. We believe it is overwhelmingly likely that the target price of $40 will be reached by 2005.

- **Fuel oil**: $100 (132% increase from 1999)

Fuel prices are currently quite high in Russia relative to Western Europe. As local refineries improve their output mix, prices should rise. However, these prices are unlikely to rise as quickly as those for other fuels. In any event, few local power stations currently use fuel oil, and fuel oil will likely remain an expensive source of electricity.

- **Coal**: $25 (212% increase from 1999)

Coal prices have been assumed to reach $25/ton by 2005. This is somewhat arbitrary, as there are no quoted world prices for Russian-quality coal. It seems roughly reasonable in view of local costs, however.

- **Coal transport**: 100% increase (same level as in Western Europe and the US)

Russia's transport fees (on a per tonne/per km basis) were about half those of the US and Western Europe in 1999. They are unlikely to exceed this after completion of the planned railroad reform.

APPENDIX B. LOAD PROFILING.

The electricity consumption of most customers is metered only on a monthly basis, while wholesale purchases are metered and billed on an hourly basis. Thus, it is impossible to know the actual wholesale cost of serving a given retail customer, because this cost depends upon how much unmeasured power that customer is consuming each hour. In order to resolve the contradiction of providing a power resale service to customers whose consumption cannot be directly observed, a process known as "load-profiling" was created/ Under this process, the distribution utilities develop estimates of end-use consumption that is aggregated by customer class. Thus, for example, the wholesale cost of serving a residential household in San Diego is estimated using the average hourly price in the Power Exchange (plus other transaction fees) weighted according to the average hourly consumption of all households in the SDG&E service territory.

SDG&E developed the 1999 static load profiles based upon a three (3) year average of electrical use (1994-1996). Rate class load estimates are presented in kWh and local time.

Rate Class 1994-1996 Averages

Class	#Customers	Share of demand
Agricultural	3,522	1%
Large Com/Ind	599	13%
Medium Com/Ind	17,485	28%
Residential	1,090,003	44%
Small Commercial	109,284	9%
Schedule AD	595	1%
Schedule A6	11	5%

Figure 26: Load Curves for Russia and SDG&E Static Profile 1999

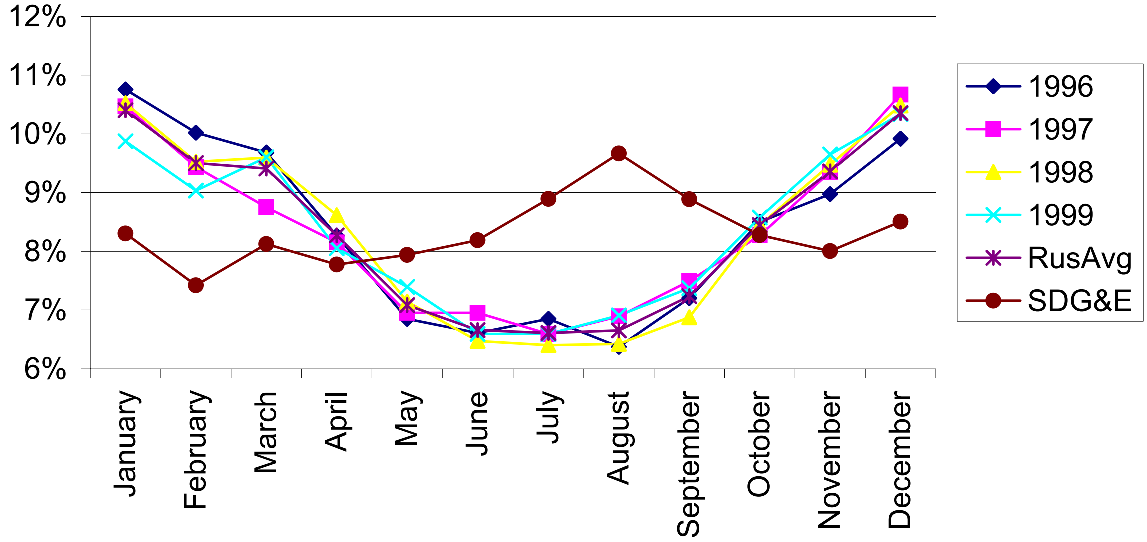


Figure 27: Load Duration Curves for Russia and SDG&E Classes

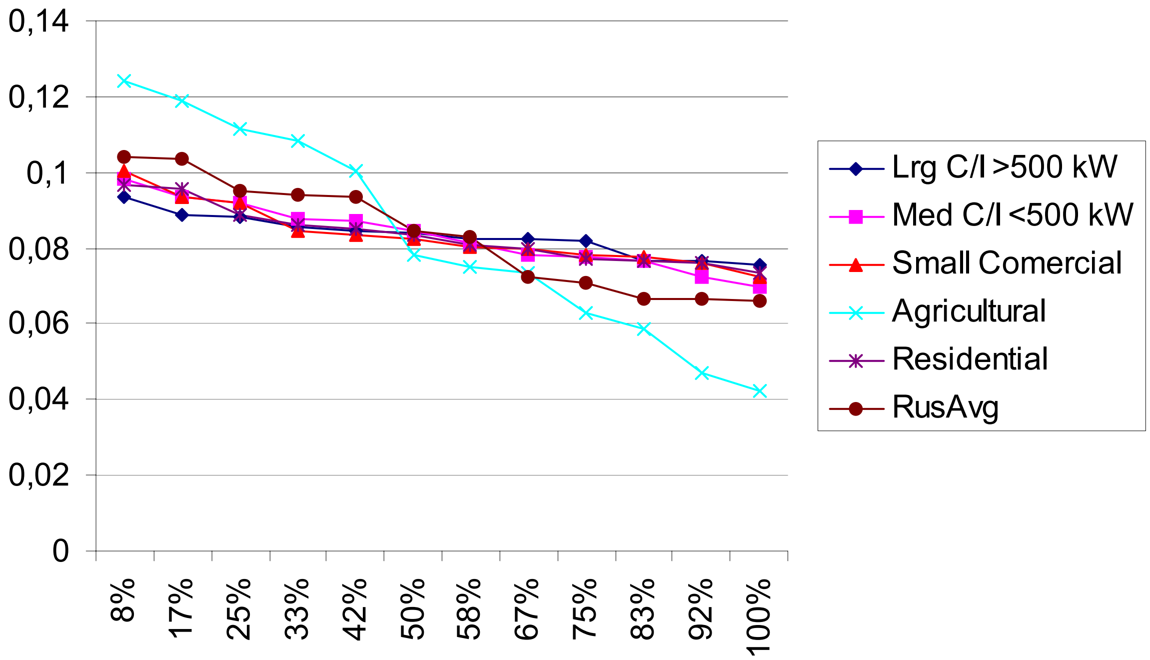


Figure 28: Hourly Load Curve for different classes, SDG&E

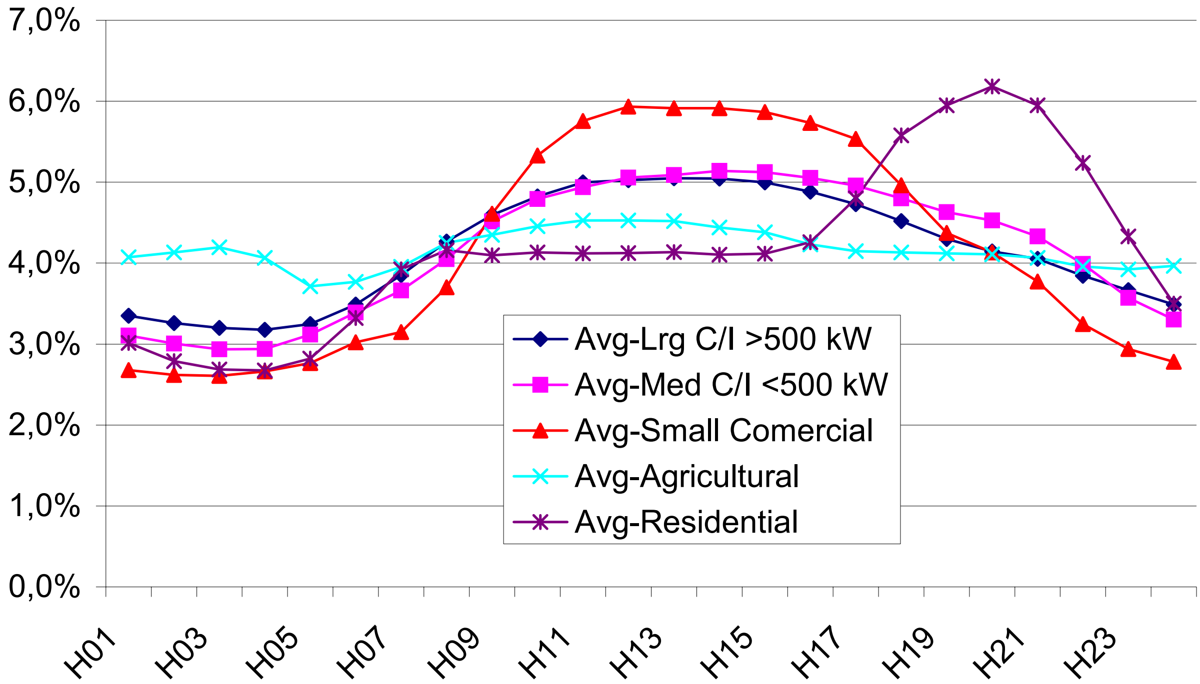


Figure 29: Hourly Load Duration Curves, SDG&E

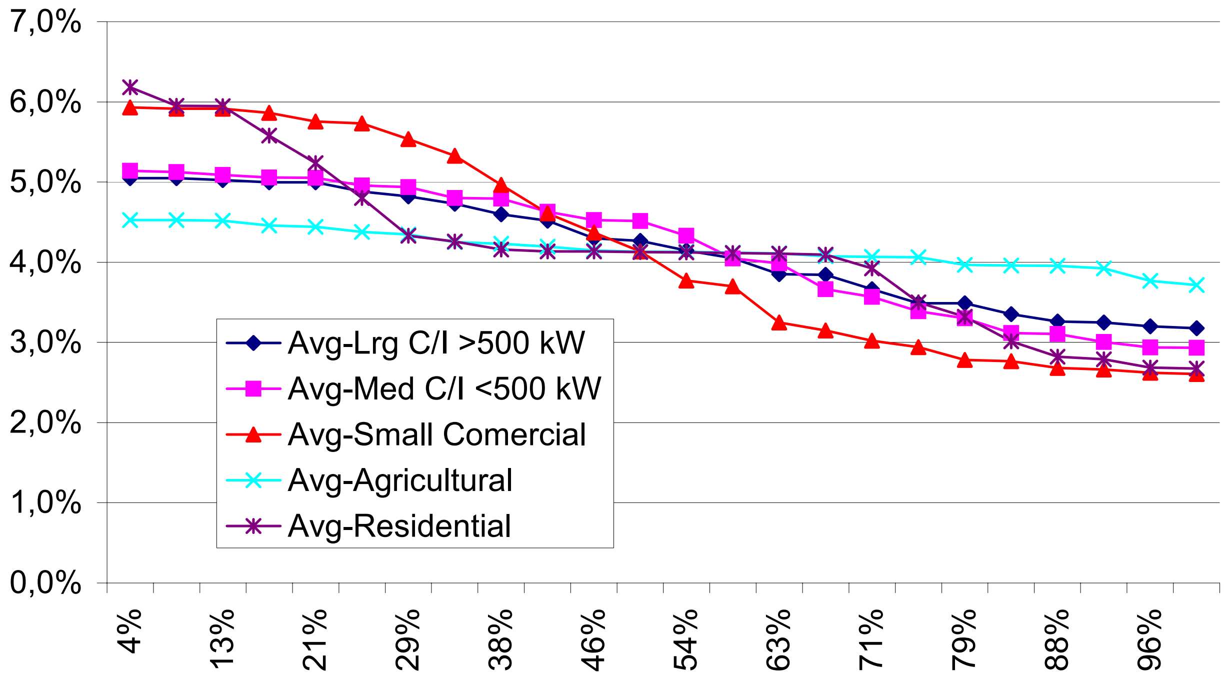


Figure 30: Monthly Load Curve, PDG&E

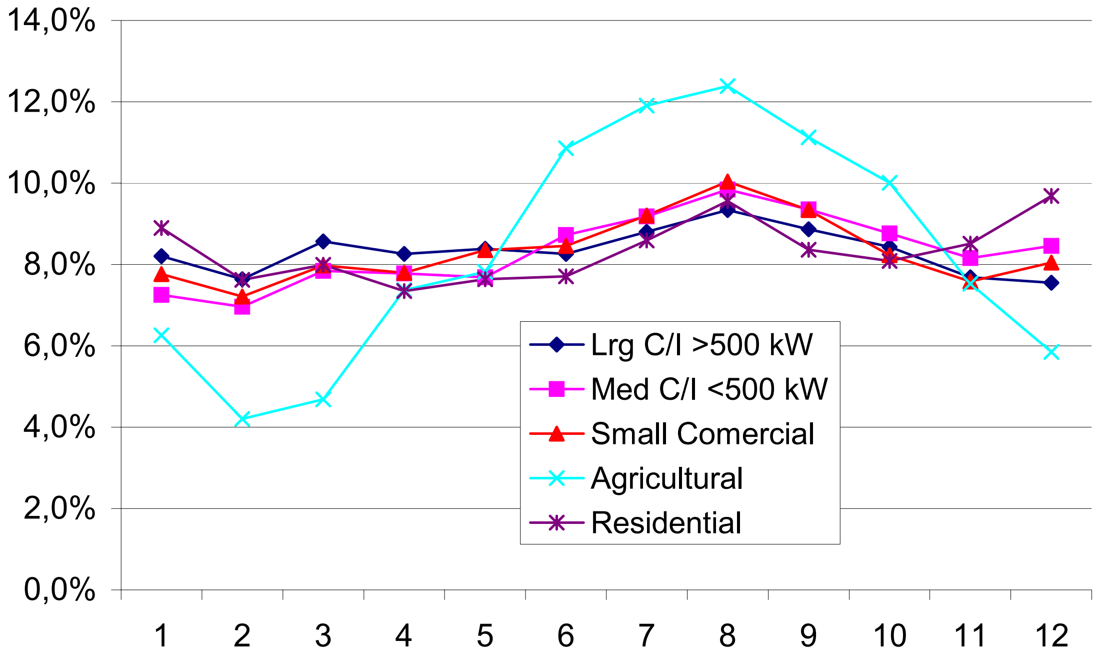
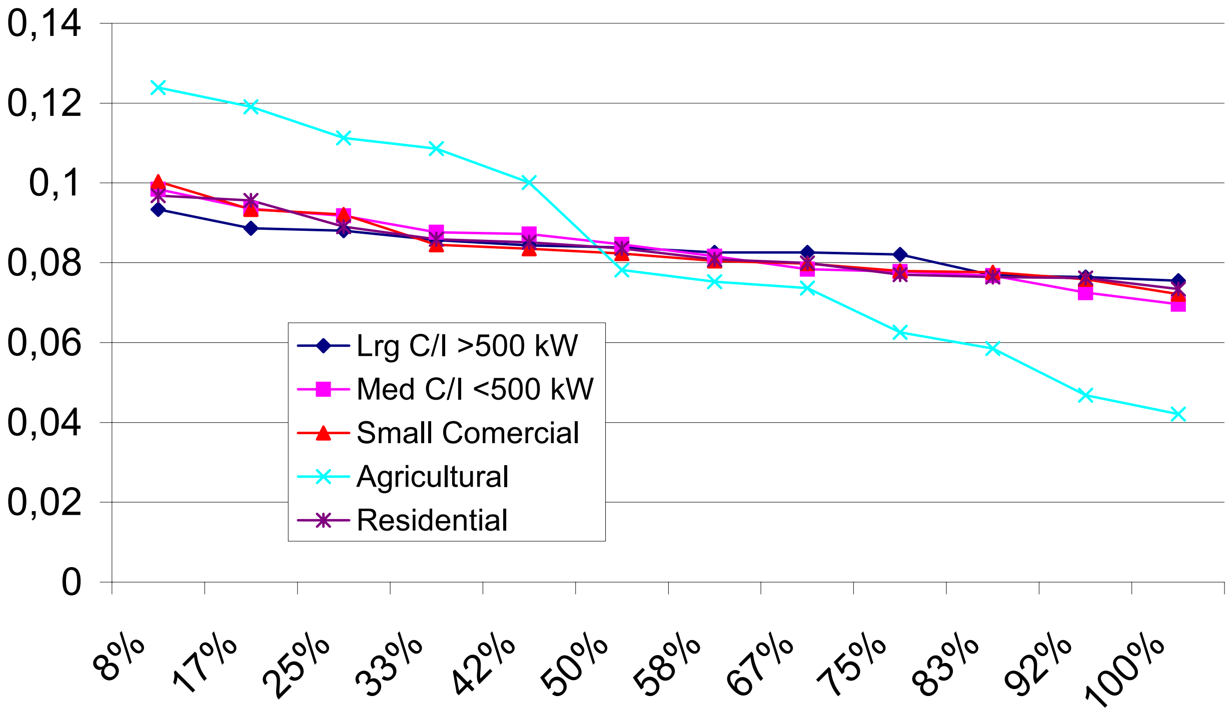
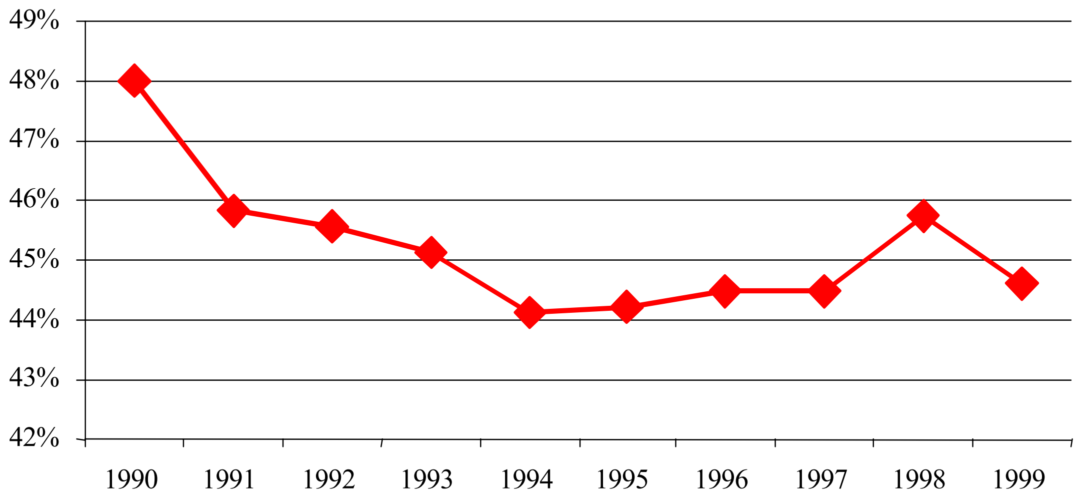


Figure 31: Monthly Load Duration Curve, PDG&E



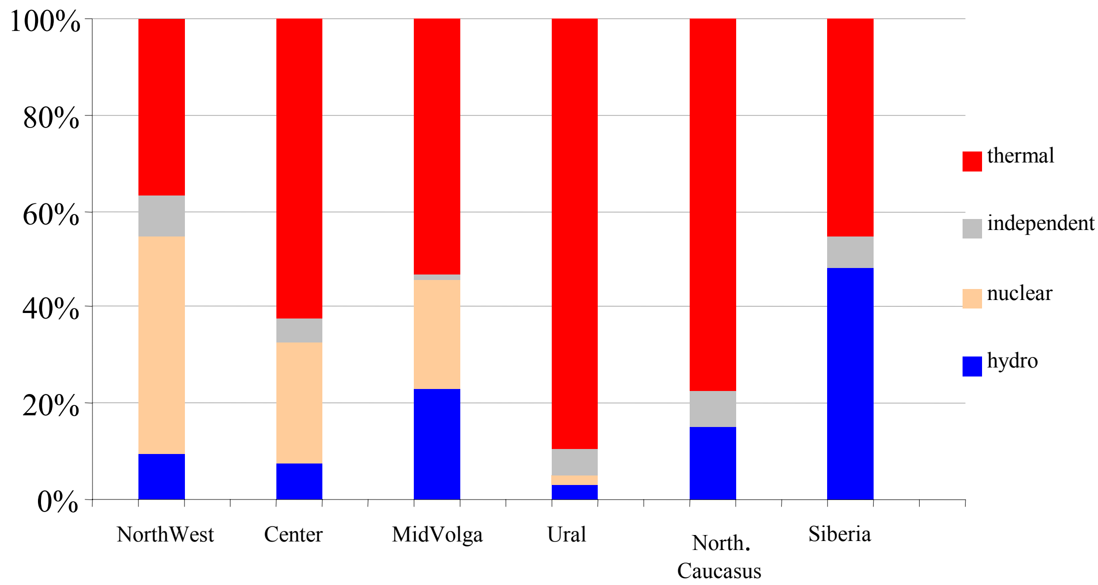
APPENDIX C. POWER INDUSTRY DATA

Figure 32: Share of thermal power stations in Russia



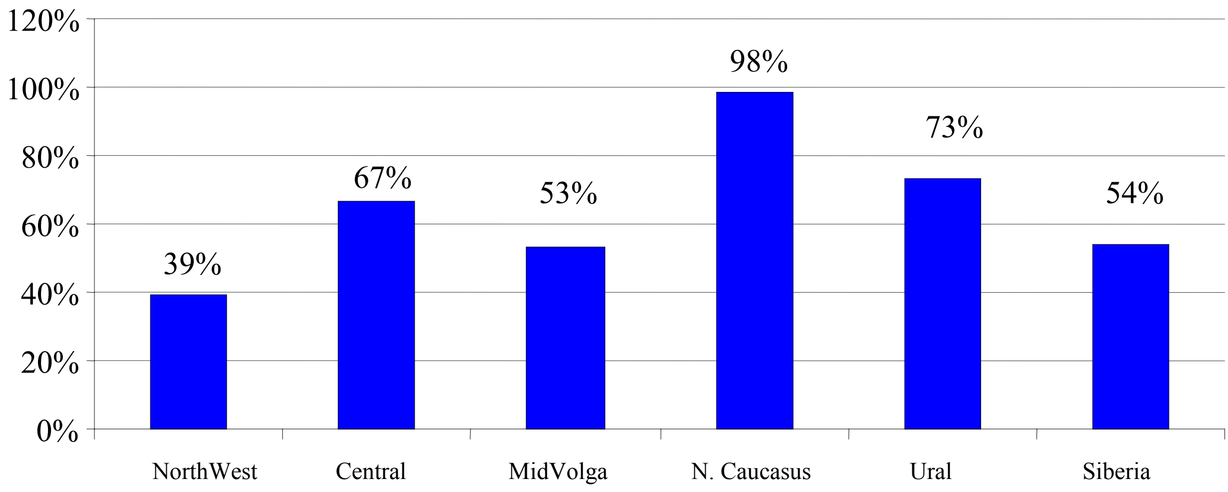
Source: Energy Research Institute, Moscow

Figure 33: Capacity breakdown, by type, 1999



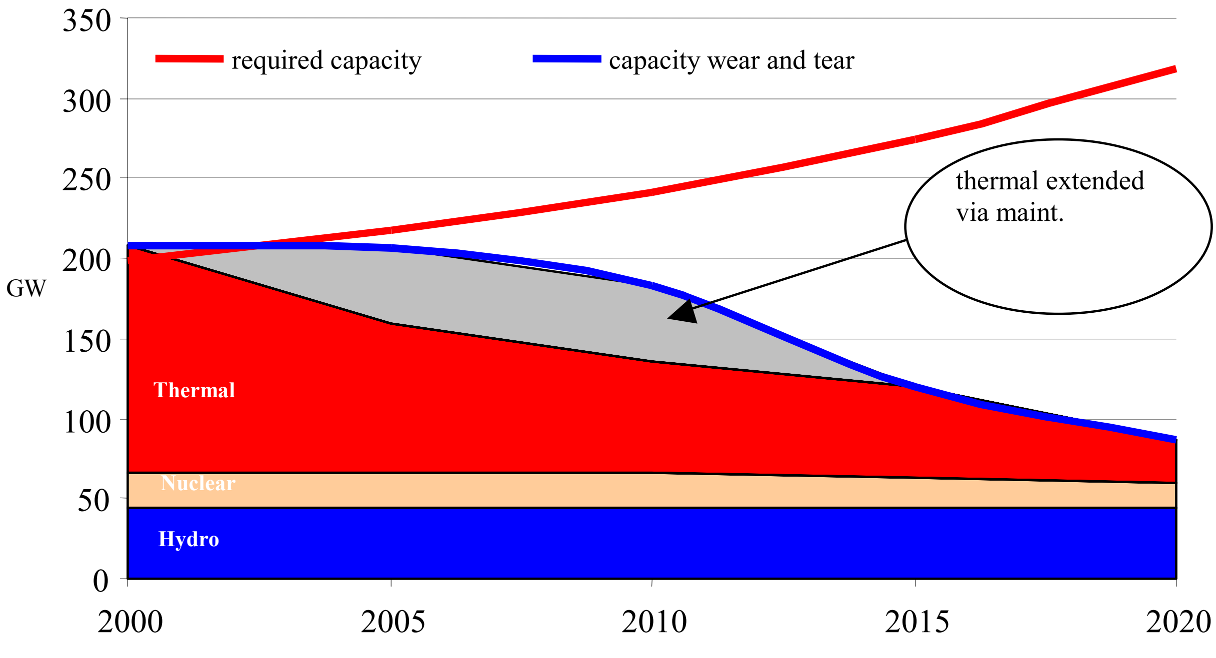
Source: Goskomstat

Figure 34: Thermal capacity, 1999



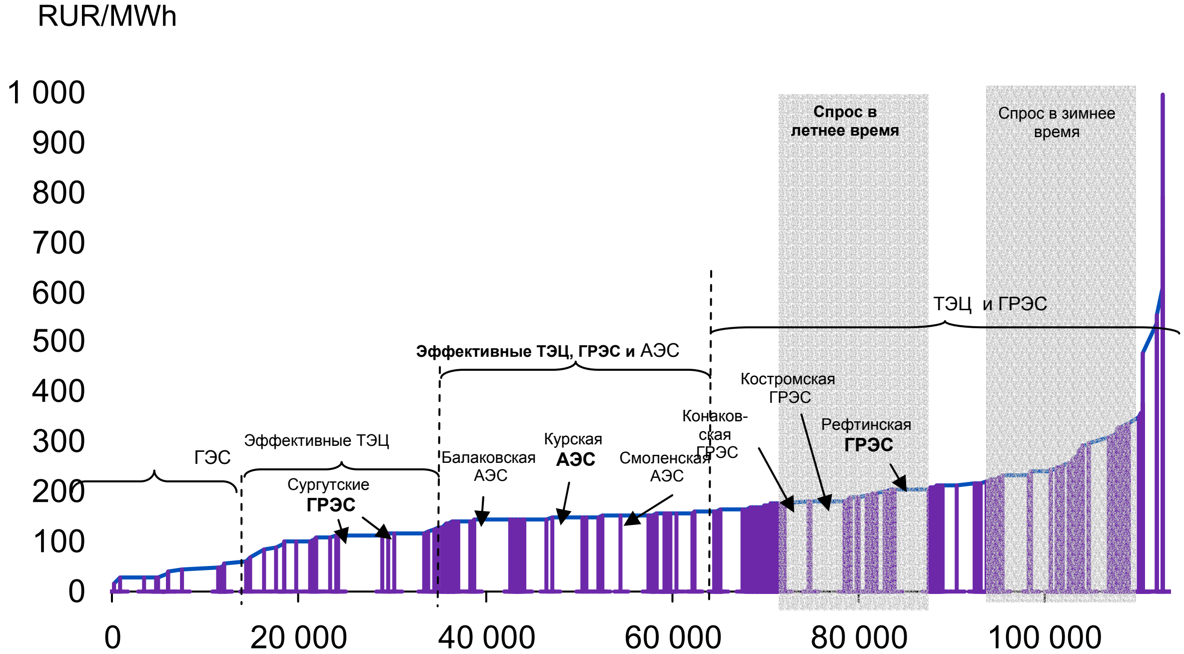
Source: Company data

Figure 35: National capacity and demand



Source: ERI

Figure 36: Supply in Central Energy Zone



Source: JP Morgan

APPENDIX D. GENERAL SFE MODEL.

This appendix closely follows Baldick and Hogan (2001):

Price cap and price minimum

Price caps are in place in many electricity markets. The detailed implementation of the price caps varies from market to market. To represent the effect of a generic price cap on the market, we follow von der Fehr and Harbord (1993) and assume that the market rules specify a price cap $\overline{p}$ and that the firms are obliged to bid supply functions that satisfy:

$$\forall i \quad S_i(\overline{p}) = \overline{q}_i \quad \textbf{(4)}$$

That is, each firm must be willing to operate at full output if the price reaches the price cap. Of course, firms might also bid so that they would be prepared to produce at full output for lower prices.

As discussed in Borenstein (2001), enforcement of this requirement necessitates that the market operator be prepared to curtail demand and not breach the price cap. Furthermore, the market operator must be able to reliably estimate the maximum marginal cost of production by any firm in the market so that the price cap can be set above the maximum marginal cost of production.

We assume for convenience that there is a known minimum price $\underline{p}$ below which no firm would be prepared to bid any non-zero supply.

For example, $\underline{p} = \min_i \{a_i\}$ is a suitable value since no firms will be willing to generate for a price that falls below the marginal operating costs at zero output of the cheapest generator.

Feasible and allowable supply functions

We require that each supply function be defined for every price in the interval $[\underline{p};\overline{p}]$. To be feasible the range of the supply function for firm i must be contained in the interval $[0;\overline{q}_i]$. That is, the supply function for firm i is a function $S_i : [\underline{p};\overline{p}] \rightarrow [0;q_i]$. Market rules require that supply functions be non-decreasing in order to be allowable as bids. That is, $p \le p' \Rightarrow S_i(p) \le S_i(p')$. The requirement that each supply function be feasible and allowable is embodied in the following:

Definition of supply function

For each $i = 1, \ldots, n$, the set $\boldsymbol{S_i}$ is the function space of feasible and allowable supply functions for firm *i* having domain $\lfloor \underline{p}\,; \overline{p} \rfloor$. That is, $\boldsymbol{S_i}$ is the set of functions with domain $\lfloor \overline{p}; \underline{p} \rfloor$ that:

1. have range $[0; \overline{q}_i]$ (so that all bids are feasible for allowed prices) and
2. are non-decreasing over the domain $\lfloor \underline{p}\,; \overline{p} \rfloor$, (so that the function is an allowable supply function).

Further we analyze differential equations with solutions that yield supply function equilibria, we will further restrict $\boldsymbol{S_i}$ to be the space of differentiable functions that are feasible and allowable. In this case, the non-decreasing constraints are equivalent to: $\forall i = 1, \ldots, n, \quad \forall p \in \lfloor \underline{p}\,; \overline{p} \rfloor, \quad S_i'\,(p) \ge 0$.

Price

At each time t $\in$ [0; 1], the market is cleared based on the bid supply functions $S = \left(S_i\right)_{i=1,\ldots,n}$ and the demand. That is, at each time t, the price is determined by the solution of:

$$D(t,p) = N(t) - \gamma p = \sum_i S_i(p), \quad \textbf{(5)}$$

assuming a solution exists. All firms receive the marginal clearing price for their supply. We say that this price corresponds to the bid supply functions S. If $\gamma > 0$ then for each *t* and each collection of choices of non-decreasing supply functions S_i there is at most one solution to (5) having $\underline{p} < p < \overline{p}$. If there is a solution to (5) in this range, then this solution determines the price at time t. (If S_i is discontinuous then we must modify the notion of "a solution to (5)" slightly; however, we will not need to deal with this issue for the supply functions we exhibit.) If there is no solution to

(5) in the range $\underline{p} < p < \overline{p}$, then the realized price depends on whether the market is assumed to have price caps or bid caps.

Price caps

In the case of price caps, the market price is never allowed to rise above $\overline{p}$. If there is insufficient supply to meet the demand at price $p = \overline{p}$ then demand must be rationed. In this case, we will assume that:

- demand is rationed to the available supply and
- all energy is sold at a price equal to the price cap.

For any particular choices $S_i, \quad i = 1, \ldots, n$, we can therefore implicitly solve for price as a function of time. That is, there is a function $P : [0,1] \to \lfloor \underline{p}\,; \overline{p} \rfloor$, which is parameterized by $S_j, \quad j = 1, \ldots, n$, such that:

$$\forall t \in [0,1], D(t, P(t; S_j, j = 1,...,n)) \geq \sum_i S_i(P(t; S_j, j = 1,...,n)), \quad \textbf{(6)}$$

with equality between the left and right hand sides except at times when demand rationing occurs. For notational convenience, we will omit the explicit parameterization of the function P and just write it with one argument, namely, the normalized time t.

Bid caps

In this alternative market structure, prices can rise to higher than $p = \overline{p}$ in order to ration demand based on price. That is, there is a cap on bids but not on prices. To implement the bid caps, we implicitly extrapolate the supply functions to being functions $S_i : \lfloor \underline{p}, \infty) \to [0, \overline{q}_i]$ by defining: $\forall i, \forall p \succ \overline{p}, S_i(p) = \overline{q}_i$, Moreover, we relax the upper limit on price and only require that $p \geq \underline{p}$. In this case there is always a solution to (5); however, the resulting price might exceed the bid cap $\overline{p}$. Again, we can implicitly solve for the marginal clearing price as a function of time. However, price is now a function $P : [0,1] \to \lfloor \underline{p}\,; \infty \rfloor$

Profit

Given a supply function S_i of firm *i* and also given the supply functions of the other firm, which we will denote by $S_{-i} = (S_j)_{j \neq i}$, , we can determine the corresponding price function P. Moreover, at any time t the accrual of profit per unit (normalized) time to firm *i* is π_{it} :

$$\pi_{it} = S_i(P(t))P(t) - C_i(S_i(P(t))). \quad \textbf{(7)}$$

The profit π_i to firm *i* over the time horizon is then given by:

$$\begin{aligned} \forall S_j, j = 1,...,n, \pi_i(S_i, S_{-i}) &= \int_{t=0}^{1} \pi_{it} dt, \\ &= \int_{t=0}^{1} S_i(P(t))P(t) - C_i(S_i(P(t)))dt \end{aligned} \quad \textbf{(8)}$$

That is, the profit π_i is the integral of the profit per unit time over the time horizon.

Equilibrium definition

A collection of choices $S^* = (S_i^*)_{i=1,...,n}$, is a ***Nash supply function equilibrium*** (SFE) if: $\forall i = 1,...,n, S_i^* \in \arg\max_{S_i \in S_i} \{\pi_i(S_i, S_{-i}^*)\},$

where $S_{-i}^* = (S_j^*)_{j \neq i}$.

In the general case, firms having capacity constraints and asymmetric costs, solutions of (9) typically violate the non-decreasing requirements somewhere over the range of realized prices over the time horizon. Baldick-Hogan Theorem helps to explain why this is the case. It shows that the solutions of the differential equation must satisfy tight bounds in order for the solution to be non-decreasing over a range of prices.

In the cases of:

1. symmetric cost functions and symmetric solutions to the differential equations or
2. affine solutions to the differential equations with affine marginal costs,
3. then the necessary conditions in Baldick-Hogan theorem are relatively mild.

If the marginal costs are not affine or if non-affine SFEs are being sought then we must return to the conditions:

$$\forall i \quad q_i = \left\{ \left[p - \frac{dC_i}{dq_i}(q_i(p)) \right] \left(-\frac{dD}{dp} + \sum_{j \neq i} \frac{dq_j(p)}{dp} \right) \right\}$$

As discussed in Baldick, Grant, and Kahn (2000), these conditions are a set of coupled differential equations that are not in the standard form for differential equations because of the summation of the derivatives. In Baldick, Grant, and Kahn (2000) it was shown that the conditions can be transformed into the following standard form of non-linear vector differential equations:

$$S^{*/}(p) = \left[\frac{1}{n-1} \Im \Im^T - I \right] \begin{bmatrix} \dfrac{S_1^*(p)}{p - C_1^*(S_1^*(p))} \\ \vdots \\ \dfrac{S_n^*(p)}{p - C_n^*(S_n^*(p))} \end{bmatrix} - \frac{\gamma}{n-1} \Im \quad \textbf{(9)}$$

where

- S*=($S_i^*(p)$), i=1…n is the vector of supply functions and $S^{*/}$ is the derivative of this vector,
- $\Im$ is a vector of all ones of length n,
- Superscript T means transpose, and
- *I* is the identity matrix.

The specification of an initial condition may partly resolve the issue of the multiplicity of equilibria that are typically possible with supply function equilibria. That is, the price cap provides a public signal to the firms that may allow them to coordinate on the equilibrium satisfying $\forall i \quad S_i^*(\overline{p}) = \overline{q}_i$ which is presumably the equilibrium that yields the largest profit given the price cap. If the solution of the differential equation for this initial condition is non-decreasing and satisfies the capacity constraints, so that the solution of the differential equation specifies an SFE, and if there is only one such SFE then the SFE may be a plausible outcome for the market.

A difficulty with solving the differential equation (9) is related to the terms in its right hand side. For each firm i, we define the marginal cost conditions to be:

$$\forall p \in [\underline{p}, \overline{p}], C_i^{/}(S_i(p)) \leq p.$$

The marginal cost conditions characterizes prices where a firm i is selling at an operating profit. In numerical experiments, Baldick and Hogan (2001) found that non-affine solutions to the differential equations typically approached the boundary of the marginal cost conditions. That is, the marginal costs approach the price for certain prices. At the boundary of these conditions, the differential equations (9) become singular because of the terms in the denominators of the entries on the right hand side of (9). Nearby to the boundary of the marginal cost conditions, the differential equations become difficult to solve because of numerical conditioning issues.

Baldick and Hogan (2001) showed that the singularity can be removed by augmenting the differential equations in a manner analogous to rearranging the equations into parametric form, as discussed for the symmetric, two firm case in Klemperer and Meyer (1989).

Even with this transformation to circumvent the problem of singular equations, the solutions to the differential equations will often reach and even violate the marginal cost conditions.

They also found that solutions to the differential equations typically failed to satisfy the feasibility constraints. However, preventing the trajectory from violating the feasibility constraints or the marginal cost conditions poses serious conceptual problems, which we were not able to solve.

They considered a number of approaches to modifying the differential equation to avoid solutions that were not feasible or did not satisfy the marginal cost conditions. For example, Baldick and Hogan (2001) considered imposing the feasibility constraints explicitly in the maximization of profit per unit time to obtain a constrained version of the problem of maximizing profit per unit time. The basic difficulty in manipulating the resulting equations into the form of a differential equation is that the dependence of q_{it} on the $S_j^{/}, j \neq i$ is no longer invertible. That is, we can longer write an equation analogous to (9) with the derivatives of the supply functions given by a function of the supply functions.

Baldick and Hogan (2001) also tried to model the capacity limit by adding "barrier terms" to the cost function that rapidly increase as the capacity is reached. However, they were not able to reliably generate solutions to the differential equations that satisfied the non-decreasing and capacity constraints.

The most serious difficulty with the differential equation approach to solving for the SFE is that the differential equations do not "automatically" satisfy the capacity or non-decreasing conditions. Baldick-Hogan Theorem implies that unless the cost functions are all very similar or there are no capacity constraints then the non-decreasing constraints will typically be violated in a solution of the differential equations, unless the range of realized prices is small enough to only cover a segment of the solution that happens to be non-decreasing. Baldick and Hogan (2001) shows that even a very slight deviation from the affine solution results in solutions of (9) that are non-decreasing only over a narrow range of prices. If the load factor over the time horizon were very close to 100% then such a solution of (9) would be an equilibrium.

However, if the load factor is significantly below 100% then most such solutions would violate the non-decreasing constraints over the range of realized prices. This analysis provides two observations. First, the usual approach to solving differential equations to obtain the SFE may not work in the case of heterogeneous portfolios of generation with capacity constraints when the load factor deviates significantly from 100%. In this case, we must explicitly impose the non-decreasing constraints.

A basic criticism of the SFE approach is that there are multiple equilibria. Certainly, if every possible specification of the initial conditions for the differential equations (9) yielded an equilibrium then this extreme multiplicity of equilibria would limit the predictive value of the SFE approach. However, when the load factor deviates significantly from 100%, many of these putative equilibria are ruled out by the non-decreasing constraints. This strengthens the observations by Klemperer and Meyer (1989) that they made for the symmetric case concerning the multiplicity of equilibria. Moreover, the price cap condition (4), when it is binding on the behavior of firms, further limits the range of potential equilibria. Such solutions could form part of an equilibrium only if either: 1. the range of realized prices was very restricted, or, 2. there were a discontinuity in the derivative of the supply functions. The first case could occur if the load factor were close to 100%. In this case, there would be a multiplicity of equilibria, with the range depending on the range of the function N, but not on the detailed dependence of N(t) on t. Conversely, extended time horizons having load factors well below 100% rule out many of the solutions of (9) from being supply functions. In the second case, we can imagine a discontinuous change in the behavior of the firms due to, for example, a binding capacity constraint being reached at a particular price. In this case, we can imagine equilibrium solutions consisting of the union of solutions of (9) that are “pasted” together at various break-points. Baldick and Hogan (2001) confirmed this observation theoretically. In the next section we will show that the numerical solutions have this appearance.

Iterations in function space

Because of the difficulties with the differential equations approach to seeking the SFE in general, we take an iterative numerical approach. Such numerical approaches can usually be expected to yield only stable equilibria, unless started at an equilibrium or unless the iterative process produces a particular iterate that happens to be an equilibrium.

Given a current estimate of the equilibrium supply functions, denoted $S_i^{(v)}$ at iteration ν, we calculate the following step directions:

$$\forall i, \Delta S_i^{(v)} \in \arg\max_{\Delta S_i} \left\{ \tilde{\pi}_i (S_i^{(v)} + \Delta S_i, S_{-i}^{(v)}) \middle| S_i^{(v)} + \Delta S_i \in \mathrm{S}_{-i} \right\} \quad \textbf{(10)}$$

where:

- $\tilde{\pi}_i$ is an approximation to π_i ,

- $S_{-i}^{(v)} = (S_j^{(v)})_{j \neq i}$, and

- $\underset{-i}{S}$ is a finite dimensional convex subset of S_i

Supply function subspace

We will use piece-wise linear non-decreasing functions with break-points evenly spaced between ($\underline{p}$ + 0,1) and ($\overline{p}$ + 0,1), where $\underline{p}$ is the price minimum and $\overline{p}$ is the price cap. At p = $\underline{p}$, we define S_i(p) = 0. At p = $\overline{p}$, we require $S_i\left(\overline{p}\right) = \overline{q}_i$. That is, set of such functions is convex. For most cases, we used 40 break-points. We also tested some of the cases using functions with other numbers of break-points to investigate whether any of the results were an artifact of the number of break-points.

An initial guess $S_i^{(0)}, i = 1, \ldots, n$ was used as a starting function to begin the iterations. We then update the iterates according to: $\forall \nu, \forall i, S_i^{(v+1)} = S_i^{(v)} + \alpha \Delta S_i^{(v)}$. $\alpha \in (0;1]$ is a step-size.

Baldick and Hogan (2001) found that a fixed step-size of $\alpha = 0{,}1$ performed satisfactorily.

Iterating in the function space of supply functions requires considerable computational effort at each iteration and is subject to the drawback that the problem of finding the search direction may have multiple local optima. In practice, we use an iterative local search algorithm to seek the solution of (10) and do not guarantee to and the global optimum of (10). Consequently, even if the sequences of converge this does not by itself prove that an equilibrium has been found.

BALDICK-HOGAN THEOREM [1]

Consider a $S_i^*: P \to R, i = 1,...,n$ solution of the differential equation (9) on an interval of prices $P = [p, \overline{p}]$. If each function $S_i^*, i = 1,..., n$ is non-decreasing on P then:

$$\forall i = 1,...,n, \forall p \in P, \gamma \leq \frac{S_i^*(p)}{p - C_i^{/}(S_i^*(p))} \leq \left(\frac{1}{n-1}\right)\sum_{j=1}^{n}\left\{\frac{S_j^*(p)}{p - C_j^{/}(S_j^*(p))}\right\} - \frac{\gamma}{n-1}.$$

Proof. We first prove the lower bound condition in (26). That is, we prove

$$\forall i = 1,...,n, \forall p \in P, \gamma \leq \frac{S_i^*(p)}{p - C_i^{/}(S_i^*(p))}.$$

The differential equation (9) collects together and rearranges the conditions (12) applied to each firm. Rearranging (12), we obtain:

$$\frac{S_i^*(p)}{p - C_i^{/}(S_i^*(p))} = \gamma + \sum_{j \neq i} S_j^{/}(p),$$

$$\geq \gamma,$$

since $S_j^{/}(p) \geq 0, \forall j$ by assumption.

We now prove the upper bound condition in (26). That is, we prove:

$$\forall i = 1,...,n, \forall p \in P, \frac{S_i^*(p)}{p - C_i^{/}(S_i^*(p))} \leq \left(\frac{1}{n-1}\right)\sum_{j=1}^{n}\left\{\frac{S_j^*(p)}{p - C_j^{/}(S_j^*(p))}\right\} - \frac{\gamma}{n-1}.$$

Let I_i be the vector of all zeros, except in the i-th place where it is equal to 1 for any $p \in P$,

$$0 \leq S_i^{*/}(p),$$

[1] proved by Baldick and Hogan (2001)

$$= [I_i]^T S^{*\prime}(p)$$

$$= \frac{1}{n-1} I^T \begin{bmatrix} \dfrac{S_1^*(p)}{p - C_1^*(S_1^*(p))} \\ \vdots \\ \dfrac{S_n^*(p)}{p - C_n^*(S_n^*(p))} \end{bmatrix} - \frac{S_i^*(p)}{p - C_i^{\prime}(S_i^*(p))} - \frac{\gamma}{n-1}, \qquad by(16)$$

$$= \left(\frac{1}{n-1}\right) \sum_{j=1}^{n} \frac{S_j^*(p)}{p - C_j^{\prime}(S_j^{\prime}(p))} - \frac{S_i^*(p)}{p - C_i^{\prime}(S_i^*(p))} - \frac{\gamma}{n-1}.$$

Rearranging we obtain:

$$\frac{S_i^*(p)}{p - C_i^{\prime}(S_i^*(p))} \leq \left(\frac{1}{n-1}\right) \sum_{j=1}^{n} \left\{ \frac{S_j^*(p)}{p - C_j^{\prime}(S_j^*(p))} \right\} - \frac{\gamma}{n-1}.$$

□