Reform of Russian Power Industry
Which Lessons from Abroad?

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abstract

In an attempt to reform the electricity industry, the Russian government has decided to break-up the major company RAO-UES into half a dozen power generating companies, a national transmission company, a unified system operator, and a holding company managing stakes in regional energos. This essay takes a critical look at the underlying approach which emphasizes competition in power generation and relies on vertical separation and centralized short term markets to achieve the goal.

The Russian electric power industry is inefficient and it lacks funds for investment but tariffs, being subsidized through low fuel cost, are low. Hence the first priority must be given to a reform of the regulatory system and an increase of tariffs, in order to improve the industry's finance, its incentives for cost cutting and the energy efficiency. Competition in generation, which would be instrumental to bring tariffs down, appears less urgent. It may be achieved through decentralized trading in long term contracts, once access to the transmission grid is opened. As international experience suggest, restructuring of RAO UES is not necessary and may even be counterproductive.

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Contents

1 Introduction

For almost a century, electricity industries used to look similar all over the world. Monopolies, either state owned or subject to some cost–based regulation of tariffs, were in charge of generation, transmission and distribution of electricity. During the last fifteen years, however, the industry underwent profound changes in many countries. Unhappy with high tariffs, policymakers reformed the regulatory system, established new markets, restructured and privatized the industry. This large scale international experiment in market structure and market design has been accompanied by a lively and still ongoing academic debate about the best way to organize and to regulate the industry.

The British government was the first to embark on radical reform in 1990. It restructured the state administered monopoly, separating transmission, a natural monopoly, from generation, considered as potentially competitive. The newly established generating companies were privatized and obliged to sell all electricity to be delivered on the next day on a central auction market, the 'pool'. The model became popular among consultants and served as a blueprint for reforms in places as diverse as California, Poland and Ukraine — and now Russia. However, in England itself the 'pool' fell into disgrace and has been abandoned in 2000.

Germany opened the electricity market much later and took a cautious approach leaving vertically integrated firms intact. The market was not imposed by central design, but merely allowed to develop by abolishing regional demarcations and by opening the networks for third party access. The trade of electricity started in a decentralized manner, mainly in form of bilateral long term contracts with large commercial customers. Much to the surprise of many sceptical observers competition quickly became fierce even though problems with fair access to the network have not been fully resolved.

In France the government remains deeply sceptical about liberalization and upholds the virtues of a centralized and vertically integrated utility, the state owned EdF. It bowed to the European Electricity Directive only to ensure that EdF is not denied access to other EU markets on reciprocity grounds. With full control over the distribution networks and the national transmission networks, a 90% share in generation and a 95% share in sales, EdF will continue to dominate the French market even after opening the grid to third parties under new regulations.

In Russia reform got to a standstill after a hasty and half-hearted privatization in the early nineties. This left the country with a mixed structure meant to be temporary. The central government retained a majority stake in the dominant player, RAO–UES, which controls more than three quarters of the generation capacity either directly or through stakes in local energos. In addition, it owns the national high voltage grid and the central dispatch. The

position of RAO–UES appears comparable to the one of Edf in France if not for the intricate conflicts within the holding itself. Due to weak mechanisms of corporate governance and the highly politicized nature of electricity charges local energos enjoyed a substantial degree of independence from the holding company — in particular if backed by regional governors.

In 2000, however, under the leadership of Anatoly Chubais, the incumbent monopolist took the initiative pushing for a radical restructuring of the industry. After a heated debate the government endorsed a comprehensive package of reforms in summer 2001, to be implemented within the next four years. As a first step, the transmission network will be further consolidated within RAO–UES which will also be in charge of the unified system of dispatch. This will enable RAO–UES to reign in local energos and bring the Russian structure even closer to the French model. By summer 2002 an independent trade administrator and rules for network access shall be established through negotiations between RAO–UES, independent producers and major costumers. Hence, the intermediate phase will resemble the situation in Germany with negotiated third party access to the grid of a vertically integrated monopolist. Finally, by 2004 RAO–UES shall spin off its generation capacities into half a dozen generating companies in order to separate the network from generation and create a truly competitive wholesale market, as it was attempted in Britain, which served as a blueprint for the initial plan of reform. Thus, during the various stages of reform Russia will move through quite different models of organizing the industry.

This paper gives a critical assessment of reform options in Russia based on the international experience. The first section provides some background information on the situation in Russia. It follows a review of the international experience, focusing on what has been achieved in terms of efficiency and competition. The final section draws the conclusions for reforms in Russia.

2 The Russian Power Industry

2.1 Basic Features

With an installed capacity of about 218 GW the Russian power industry is about the same size as the Japanese, or the French and German industries put together. Electricity production has fallen by about a quarter from its 1990 Soviet-era peak. This reflects the economic decline and would have been even more pronounced without the steady increase of residential consumption. Industrial electricity consumption decreased less than output, which reduced the traditionally low energy efficiency even further. The last two years witnessed a modest increase in demand, but the electric power industry still has large overcapacities. After a decade of almost zero investment, however, there is an increasing need to replace

and upgrade worn out equipment.

Capacity	%	**fossil fuel**	%
thermal electric power	34	natural gas	62
thermal cogeneration	35	coal	30
hydro	22	fuel oil	8
nuclear	9		

About two thirds of the capacity consists of thermal plants, predominantly fired with natural gas. Hydrostations contribute a little more than a fifth and nuclear stations a little less than a tenth of the capacity. A particularity of the Russian energy system, is the high share of thermal cogeneration-plants, which provide the backbone of the heating system in the cities. They account for about a third of the capacity, but being used more intensively, they account for half of the electric power production. These plants are very fuel efficient when producing electricity and heat together (although high losses of poorly designed and poorly maintained heat–transport systems reduce this advantage). Fuel efficiency decreases sharply when they produce only electricity.

Consumption	GWh	%
Industry HV	365	44
Budget and resellers	112	14
Residential	64	8
Commercial	46	6
Agricultural	28	3
Other	34	4
Exports	13	2
Subtotal	662	80
internal consumption	166	20
Total	828	100

An outstanding feature of the structure of electricity consumption is the large share of high voltage industrial customers. Leaving losses and internal consumption aside, they account for about half of the final demand. Customers financed from the state budget and resellers, which are often politically connected, are the second largest group. The problems of non–payments have been most severe among this group. The share of resellers is declining since RAO UES introduced a policy of direct marketing. Although residential consumption has increased substantially over the past ten years, its share is still small by international standards. This is also true for low voltage commercial demand.

2.2 Structure of the Industry

The current structure of the Russian electric power industry was shaped during a hasty and half hearted privatization in the early 90th. The Government divided all non-nuclear stations between RAO UES and 74 local energos while 9 nuclear power plants remained under state ownership and are currently managed by Rosenergoatom. The distribution network, the regional transmission lines and some trunk lines, connecting power plants and large customers to the interregional grid, were given to regional energos, which were granted a local monopoly on distribution. In addition they obtained the majority of generation assets in their respective region including the cogeneration plants, giving them a 80% share

in the heat–generation capacity. However, most large hydro-stations and fuel-fired stations were given to RAO UES which also gained full ownership over the high voltage transmission network and over the central dispatching unit, which manages interregional electricity flows.

Market Structure

UES plants	25 %
UES energos	49 %
Rosenergoatom	10 %
Irkutskenergo	6 %
Tatenergo	3 %
Krasnoyarskaya GES	3 %
industrial plants	4 %

The Federal Government retained a majority stake of 52% in RAO UES, which in turn was made a holding company for, mostly controlling, stakes in the regional energos. The remaining shares were given to employees or sold in voucher or cash auctions. Due to the weakness of the central government at that time the implementation in the regions proved to be difficult.[1] In particular Irkutskenergo and Tatenergo with a combined capacity of 9% prevented the transfer of shares and remained independent from UES. In 1999 UES lost control over the Krasnoyarsk hydroplant which was acquired by aluminum smelter but it gained a controlling majority in Moscow's regional energo, Mosenergo, by handing over two large power plants. Today RAO UES controls almost three quarters of the installed generation capacity either through stakes in large power plants or in 72 out of 74 regional energos.[2]

Privatization, however, resulted in protracted problems of poor corporate governance. As many other industries UES was plagued by inefficient administration and poor internal controls allowing embezzlement and theft. Political conflicts with regional governments made it difficult for the company to establish control over its local subsidiaries and to implement a consistent strategy to cope with increasing problems of non–payment and barter deals. In spite of huge capacities, the security of power supply was undermined by unpaid fuel–bills and increasing wage–arrears. In 1998 Anatoly Chubais was made CEO of RAO–UES to bring the house in order. The following three years witnessed a successful corporate turnaround. Chubais put together a new team of top managers and replaced almost 80% of the general directors at UES' 250 subsidiaries. By reorganizing sales, insisting on cash–settlements and cutting off non–payers, UES almost wiped out barter–deals, of which 40% were hidden losses anyway, increased cash-collection to almost a 100% and started to recollect debts.[3] In 2001 the company reported its first profit of $16.7 million under international accounting standard, compared to a loss of $12 million in 1999. Investment almost tripled during same

[1] See Opitz (1999) for further details.

[2] For details see Appendix 6.1 and 6.2.

[3] Under increasing pressure to collect unpaid bills energos more frequently resorted to the treat of black-outs. Government and other 'Budget institutions' are usually those with lowest payment discipline. Institutions subjected to power cuts include, hospitals, air traffic control center, an Arctic submarine base, a strategic missile base, prisons. However, military bases, prison authorities or even municipal governments often respond violently sending troops or police units to prevent blackout or forcing companies to restore power supply at at gunpoint.

period.

Wholesale Market			
Supply		Demand	
UES Plants	52 %	shortage energos	97 %
Roseneroatom	41 %	industrial users	3 %
surplus energos	7 %		

The current Federal Wholesale Market of Electricity and Power FOREM was established by presidential decree in 1996, giving UES a 80% stake and Rosenergoatom the remaining 20% in the venture. About 40% of the final demand for electricity is obtained through the wholesale market. Since the largest power plants were transfered to UES and Rosenergoatom, they are the main suppliers to the wholesale market, together accounting for about 93% of total supply. The remaining 7% are provided by a small number of 'surplus' energos (Tyumenenergo, Orenburgenergo, Irkutskenergo, Mosenergo). Regional energos account for 97% of the demand while the direct participation of large industrial customers contributes only a minicules 3%. However, FOREM does not operate like a proper market. UES turned it into a clearing mechanism for power transactions carried out according to its own schedule. Rosenergoatom claims that UES abused its power to match generators and customers to select the most reliable payers for itself.

There are major problems with the current two–layer structure. UES is abusing its monopoly over the interregional high voltage grid and the wholesale market by preventing its competitors access to the most lucrative customers (including exports) and by overcharging regional energos using the proceeds for new investment in generation. Regional energos, in turn, abuse their franchise monopoly by favouring own production over cheaper supply from the wholesale market and their control over important trunk lines to prevent large industrial customers from direct access to the wholesale market.

2.3 Regulation of Tariffs

Tariffs at the wholesale market and the usage fee of the transmission grid are regulated by the Federal Energy Commission (FEC) which is also in charge of domestic prices of gas. Regional Energy Commissions (RECs) are supposed to determine tariffs at the retail level. In principle tariffs are calculated to allow for cost–recovery and to leave some funds for investment. In practice, a simple cost–plus formula reimburses cash–expenses, with little regard for depreciation or cost of capital, and a political decision is made on how much should be invested in the sector. Hence, the FEC in fact approves both, investment plans and increases of tariff.

In 2001 the average wholesale tariff was about 10$ MWh, but being set individually for each plant, tariffs vary widly between 0.5$/MWh for the Sayano-Shushenskaya hydro station and

Table 1: Cross Subsidization: selected regional tariffs [$/MWh]

	industry	transport	agriculture	residential	
AO-energo				city	village
Mosenergo	large 17.80 middle 29.78 small 27.38	20,20	15,06	21,56	15,06
Buryatenergo	27,90	20,54	26,46	19,17	19,17
Irkutskenergo	5,86	5,82	3,42	3,42	2,39
Krasnoyarskenergo	10,70	10,98	11,36	9,58	9,58
Novosibirskenergo	18,76	18,76	13,69	16,77	11,64
Tomskenergo	22,61	17,73	15,74	15,74	15,74

20 $/MWh for Cherepetskaya, an old coal-fired plant.[4] All regional energos have to pay a fixed fee for the usage of the transmission grid, which is based on their total deliveries to final customers, not on their volume of trade in whole–sale market. In the recent past grid fees have been increased to provide RAO UES with the means to finance investment. However, this policy remains highly controversial and independent energos refuse to pay grid fees since 1999.

At the retail level regulation sets rates for different group of customers. As Regional Energy Commissions are often heavily pressured by local governors, the process of tariffs setting is even more politicized and opaque than on the federal level. This holds true also for the settlement of disputes over nonpayment, in which heavy handed tactics are common. A much critized feature of retail tariff regulation is cross subsidization between different groups of customers. As the tariff schedule (page 6) reveals, residential tariffs are generally lower than industry tariffs. But the degree of cross subsidization varies substantially across different regions, as do other features of the schedule. In some regions agriculture obtains electric power cheaper than industry and city residents. In other regions it is the opposite.

The regulation of tariffs lacks coordination between regulation at the federal and regional level. In particular, there is no mechanism to pass an increase of fuel cost and wholesale tariffs through to retail tariffs. However, the most serious problem lies in the level of tariffs, which is exceptionally low by international standards. Since the collapse of the Soviet Union tariffs have decreased in real terms from their already very low levels. In 1998 devaluation brought a further sharp drop of tariffs, down to less than a tenth of the European average. Thereafter, tariffs have increased in real terms but the current level can only be maintained because the cost of fuel, accounting for about 2/3 of the variable cost of thermal power plants

[4] See appendix 6.2 for further details.

are kept far below world market prices. Due to export restrictions gas, the most important fossil fuel, is trading at about a tenth of the price in western Europe. While distorted prices enable the power industry to settle their bills at current tariffs, they also encourage a highly inefficient use of energy. As a result, Russian society is heavily subsidizing wasteful energy consumption through lost export revenues, uncompensated environmental damage, and depletion of the capital stock in the power industry. Back of the envelop calculation suggests that bringing the price of electric power anything close to the long run opportunity cost of society would require a fivefold increase in real terms.

2.4 The New Drive for Reform

Interestingly, in Russia, it was the management of RAO-UES which initiated a new round of reforms, whereas in most other countries structural changes had to be imposed upon the incumbent firm. Backed by a study of Arthur Anderson Consulting, UES' early proposals stressed vertical separation of transmission and generation. A government owned grid company should eventually consolidate the whole network, including many parts currently under control of local energos. Most power plants would have been transferred into a small number of generating companies, which were to be privatized at a later stage. Local energos would have been left with little more than the cogeneration plants. All generators would have been obliged to sell their electricity on designated wholesale markets, the 'pools'. Local retailers would obtain electricity from their respective 'pool' and sell it to the final customers. Furthermore, tariffs should increase to generate revenues for investment, perhaps by a 100 per cent till the year 2004. Cross–subsidization was to be abolished and future regulation of consumer tariffs should be based on cost and whole-sale market prices.[5]

The overall approach was clearly inspired by the British model, although in England itself, important elements of it were just about to be abolished at that time. More importantly, the point of departure could hardly be more different. The Thatcher Government started with a consolidated structure, the Central Electricity Generation Board, which was in fact an agency of the central government. RAO-UES, in contrast, is a conglomerate, with substantial private ownership of shares, both in the mother company and in its many subsidiaries. However, during the planned process of restructuring, the central management of UES would have gained a firm hold over major bottleneck facilities, such as the network and the dispatch of power plants. This would have provided it with the leverage to reign in local energos.

The UES proposals met strong opposition from presidential advisor Andrei Illarionov and regional governors who objected the large scale transfer of assets. They favoured a consolidation of regional energos and wanted to retain vertical integration at this level. Only the

[5]for details see RAO-UES (2001) and Arthur Anderson Consulting (2001).

high–voltage national network should be centrally managed by a dedicated grid-company. After a working committee chaired by Tomsk Governor Victor Kress failed to find a compromise, the government, drafted its own resolution, which, surprisingly, has been welcomed by both sides.[6]

In principal, the government still endorses the idea of vertical separation. By 2004 UES is to be split into half a dozen power generating companies, a national transmission company, a unified system operator, and a holding company managing stakes in regional energos. The energos, however, should be consolidated into larger companies, reducing their number down to about 40 from currently over 70. Although 'separated accounting' and 'vertical unbundling' is mentioned, there are no concrete plans developed or deadlines set. This gives the impression, that they will probably remain vertically integrated and it is only RAO-UES which will be broken up. However, this is only the third step of the plan, and it appears as if the first two steps are of much more importance.

Step one, already settles the fight be over the bottleneck facilities, such as the transmission grid, the authority of dispatch and exports. Not later than by 1st February 2002 a federal grid company and a system operator shall be established, each as a 100% subsidiary of RAO-UES, though, with the special provision, that state representatives have a majority on both boards. The grid company will only obtain the high-voltage grid and important trunk transmission lines and the government will set the criteria for the latter. Furthermore the grid company has to purchase transmission lines currently owned by the energos. This appears to be little more than the management of RAO-UES could have done anyway. But it is only with the backing of the federal government that RAO–UES will be able to force the local energos to hand over strategic trunk lines and consolidate its control over the high voltage grid.

Furthermore, the system operator will unify the central dispatch unit and the regional dispatch units within a hierarchical structure, effectively reestablishing the centralized system which was lost during the early reforms. Since the operator's responsibilities are broadly defined, RAO–UES will increase its leverage over the local energos and independent producers. This could be used to increase the capacity utilization of its own plants for which it claims higher cost efficiency. The first step of the reform clearly follows the overall pattern of Russian politics since Putin's inaugoration, that is to strengthen central power over the regions.

The reorganization of the wholesale market, which is to be completed by summer 2002 could be the first step towards competition. A new non–profit partnership, the Administrator of the Trade System (ATS), shall replace FOREM. The Power of UES in this venture is curbed by limiting its stake to an initially 50% scheduled to decline to 25% within a year. The

[6] See Working Group (2001) and Government of the Russian Federation (2001).

working group developing a concept for the ATS is composed of the largest producers and the largest customers to ensure that all interests are taken into account. Current proposals envisage a central auction market for short term contracts (hourly intervals for the next day) which is then followed by a one hour ahead balancing market.

Reforms also include an overhaul of the regulatory regime. Based on the FEC a Unified Tariff Agency should have been established by late 2001, subordinating the RECs. The body will be responsible for setting tariffs for all natural monopolies, including electricity, gas, railways and telecommunications. The centralization of tariff setting will probably increase transparency somewhat and make changes in fuel–tariffs, wholesale tariffs, transmission fees and retail tariffs more consistent. There are also plans to reduce cross subsidization and to include an element of capital cost into the tariffs. However, the original deadlines for the establishment of this agency have already slipped, and the recent attempt to increase tariffs was halted through direct intervention by the prime minister.

3 International Experience in Reforming the Power Industry

Reforms of the power sector can be characterized at three levels: (i) privatization and regulation, (ii) market structure, (iii) market design. The first level refers to the traditional task of ensuring public interest in natural monopolies. Here we find a common trend, with many countries moving away from direct state management and cost–plus regulation. The second and third level relate to a more recent drive to open the industry for competition. In the electric power industry transmission and distribution networks are natural monopolies but they typically account for less than 1/3 of the total cost of providing electricity, while power generation contributes around 2/3 (a small share coming from metering, billing etc.). Economies of scale are generally considered to be of little importance in power generation.[7] This assessment led to high rising expectations about the role competition can play in achieving higher efficiency and lower tariffs. Countries, however, differ in their overall emphasize on competition as well as to their approach to achieve it. The major questions with respect to market structure are, how much vertical unbundeling (or separation) and how many players are needed to ensure competition. Depending on the structure of the industry, markets for the exchange of electric power, transmission rights etc. have to be

[7] One has to bear in mind, however, that economies of scale are defined in relation to the relevant market. Hence, it is necessary to look into both, the technology of generation (optimal plant size) and the capacity of the transmission network (the size of the market). If transmission constraints lead to 'load pockets' as it sometimes happens during peak load conditions, the relevant market may become very small indeed. In power generation economics of scale may be temporarily and locally very important even if they are generally not.

Reforms in the Electric Power Industry

<table>
<tr><td colspan="4">historical situation:
vertically integrated monopolies; state management or cost–plus regulation</td></tr>
<tr><td colspan="4">recent changes:
incorporation / privatization / improved regulation (price–cap)</td></tr>
<tr><td></td><td colspan="3">network access for competition</td></tr>
<tr><td></td><td>third party access
(negotiated)</td><td colspan="2">vertical separation</td></tr>
<tr><td></td><td>decentralized market
for long term contracts
later voluntary
short term market</td><td>compulsory, centralized
short term market,
but
largely covered by long
term contracts</td><td>compulsory, centralized
short term market
no
long term contracts</td></tr>
<tr><td>Spain</td><td>Germany</td><td>England</td><td>California</td></tr>
</table>

developed. Market design ranges from voluntary, decentralized trade in long term contracts with negotiated access to the transmission grid to compulsory trade of short term contracts for delivery on the next day in centralized power exchanges. For a stylized overview see chart on page 10.

Economic efficiency requires the minimization of cost (internal efficiency) with prices staying closed to marginal cost (external efficiency). Hence, we will evaluate reforms on two accounts: First, did they reduce the cost of providing electric power to society? Second, did they pass these gains on to residential and commercial customers by lowering tariffs? When evaluating the international experience, one has to disentangle the effects of improvements in the regulatory framework and the impact of competition under different forms of market structure, trade systems and network access.

3.1 Approaches

Privatization and Improved Regulation

Regulation usually faces a trade–off. Under traditional cost–plus regulation, as well as under state management, tariffs just cover cost, but these are inflated due to the lack of incentives to minimize cost. Clever price–cap regulation of privatized monopolies can achieve cost–efficiency, but due to informational constraints of the regulator it is difficult to achieve also low tariffs. However, it is well known from economic theory that this trade off is easier to resolve when cost structures are well known and technological uncertainty is of little

importance — as it happens to be the case in the electric power industry. This suggests, that privatization combined with good regulation may provide reasonably good results.

In many countries the regulatory framework has substantially improved over the last two decades. For example, England started with a centralized, vertically integrated utility, directly managed by the state. Then ordinary management decisions were transferred to newly created corporations, later to be privatized, while a new, fairly independent, agency was established to protect the public interest. Calculation of tariffs was based on a new, dynamic price–cap formula. Tariffs adjust to inflation, measured by the retail price index, also decrease over time, typically in the range of 2%-4% annually, reflecting the expected gains in productivity. Since the formula is fixed for a period of five years before being reviewed, the regulator cannot wipe out the gains from increased cost–efficiency through a downward adjustment of the price-cap. This long term commitment encouraged power providers to reduce cost much faster than anticipated. But as tariffs were not indexed on fuel cost, the industry could also reap huge windfall profits when these declined in the early 90th.

In Germany, power utilities have always been managed as private corporations, though many of them with a substantial share of public ownership. During the 70ths, a period of high and variable rates of inflation, increasing fuel–prices and wages, power companies used to apply regularly for a rise in tariffs referring to their increased cost. Since there was no clear formula for the calculation of tariffs, regulators approved tariffs in accordance with recent increases in cost plus a mark up for the return on equity. This cost–plus–regulation not only destroyed incentives for cost efficiency, it even encouraged overinvestment. However, there was no procedure to decrease tariffs if cost had declined — ecxept if power companies would have asked for a review. Thus, the firms could quietly pocket the profits from cost reductions when a combination of decreasing fuel prices and low inflation made an annual review of tariffs redundent during the 90th. Hence, it was a coincidence rather than a deliberate change in policy which led to improved incentives for cost efficiency in Germany.

Moving towards competition

By the mid 90th the focus of attention had moved beyond improved regulation towards opening the industry for competition. Many European countries were obliged to open their markets due to the regulations of the European Union. But they were fairly free to decide how new power suppliers should gain access to the grid and how markets for electric power should look like.

Vertical separation and centralized short term markets. Apparently, the easiest way to establish a level playing field for competitors is the complete separation of the trans-

mission network and system operation from power generation. An independent system operator with no self interest in generation will have no reason to favor a particular supplier.[8] Separation also helps to create a large market. Lacking own capacity, the system operator has to buy all the electricity needed to satisfy demand from independent generators.

In England this market was established by obliging all generator companies to sell one day in advance through a central auction market, the so called 'pool'. Regional electricity companies bought electric power from the pool and distributed it to final customers. This approach had the advantage, that the old system of central dispatch could be kept in place. The information about the cost of the various power plants which previously was raised internally within the integrated firm, was simply replaced by the generators' offers to the pool. Obviously, as long as the new generator firms truthfully revealed their marginal cost, the dispatch will be the same as under central planning.

The importance of the English short term market was, however, diminished by the fact, that deliveries were largely covered by long term contracts. After the initial contracts expired in 1993, most of them were renewed to hedge the risk of volatile prices of the 'pool'. While there has been a shift from 3–years contracts to annual–contracts, only about a tenth of the deliveries resulted from unhedged spot market based transactions.[9] Long term contracts have also been essential for the investment in new small scale combined cycle gas turbine power plants. Typically the so called Independent Power Producers, which were in fact often joint ventures with a regional electricity companies, signed contracts for the sale of electric power over 15 years. These long term contracts in turn provided the security for a 15-years purchasing contract of gas. Perfectly hedged against price risk over 15 years, the new plant could be financed with little equity and low capital cost. There was no uncertainty of selling into a volatile spot market, no risk of retaliatory price wars by incumbents, or loosing customers.[10] Given that the regional electricity company often had an equity stake in the new plants which in addition were tied by long term contracts, the vertical separation of the industry was eroded by new investment, a process later accelerated by mergers.

California also relied on vertical separation and developed an even more advanced system of short term markets, with special submarkets for reserve capacity etc. But in marked contrast to most other countries it prevented firms from entering into long–term contracts. As a result short term markets had to shoulder the whole burden of coordinating supply and demand.

[8]However, it is not clear at all that a vertically integrated utility will favor own generation for strategic reasons. Under fixed–price regulation, cost incentives tend to be good, so that the utility has an interest in finding the cheapest supplier. For an analysis of strategic considerations, although in the telecommuncation industry, see Weisman (1995) and Reiffen (1998).

[9]For a detailed account see Green (1999).

[10]See Newbery (1998) and Centre for Economic Policy Research (2000), Chap 6. for details

Negotiated Third Party Access In Germany, reforms had to be enacted in a rather complex environment. There were about a thousand utilities, all legally protected local monopolies, many of them with a substantial share of private equity. Some of them were tiny consisting only of a municipal low voltage distribution network, others were huge vertically integrated structures with a capacity to serve a large industrialized country. The eight biggest of them, combining 80% of the generation capacity, jointly operated the high voltage transmission grid. There was no independent central grid–company or system operator but commonly agreed rules allowed for a regular exchange of electricity. In a sense this was a kind of primitive wholesale market used by the big utilities to optimize the dispatch of their power plants.

Any restructuring of the assets of the industry would have clashed with property rights of its owners and the political interests of the states and municipalities. Hence, the German government only abolished the system of regional demarcations. The first step was the deregulation of the wholesale market in 1998, allowing high voltage commercial customers a free choice of their supplier. Two years later, the retail market was liberalized, when low voltage customers were also allowed to change their provider. After deregulation the industry began to consolidate through mergers and aquisitions.

The German government did little to stimulate competition. It did not even create a special regulatory framework to ensure fair access to the transmission and distribution networks. Any abuse of market power is liable only under general competition law. Hence it was left to the market participants to negotiate the terms of network access. A first framework for pricing network access, so called 'Verbändevereinbarung I', and a 'grid code' were established through negotiations between the associations of major producers and customers in 1998. The criteria for pricing transmission services were very complex, depending among others on voltage–level, capacity and distance between trade partners. But the agreement established the right of generators to inject into the grid which could be revoked by the grid company only in exceptional conditions. In 2000 a second agreement, the 'Verbändevereinbarung II', simplified the pricing of transmission services considerably by moving to a point of connection model, differentiating only two trade zones in Germany. However, both agreements stipulate only rules for determining cost based tariffs for transmission. The responsibility for setting the tariffs rests with the grid operators. The second agreement made possible the trade of standard contracts and in the same year two competing power exchanges started operating. They merged in 2001. Trading at the German power exchange is voluntary open to everyone. The share of electric power traded at the exchange is small compared to what is exchanged under long term contracts.

3.2 Improving efficiency

With respect to efficiency in the electric power industry it is useful to distinguish between a short term, a medium term and a long term perspective. The first refers to the use of existing assets, in particular the cost minimizing real time dispatch of power stations. The second is determined by the number and qualification of employees, suppliers of fuel, investment on maintenance and repairs. In the long run, efficiency depends also on the location, fuel type and size of power plants, the layout and capacity of the transmission system, and the mix of base–load and peak–response generators, capacity margins of the overall system etc. What is the experience of improving efficiency in western countries?

Medium Term Efficiency. Once liberalized from direct state interference and the disincentives of cost based tariff–regulation the industries were able to lower significantly the cost of providing electricity. This was achieved by reducing staff, cutting down unnecessary investment, and by switching to cheaper fuels — i.e. improving medium term efficiency. In Britain as well as in Germany companies became reluctant to yield into government pressure to buy expensive domestic coal and turned to cheaper imported coal instead.[11] New plants were designed to run on gas and ever since firms worry about cost, no one even thinks about building prestigious nuclear power plants. In England and Wales labour productivity in privatized firms doubled within a couple of years and in Germany employment fell by almost a quarter between 1991 and 1998.[12]

However, it is worthwhile stressing, that this has been achieved without competition. In England competition remained weak (see below) and in Germany efficiency had increased before markets were opened to competition, though one might argue that liberalization has been anticipated. Hence, Spain provides a more convincing example. In 1987, long before the general drive towards liberalization, the 'Marco Legal Estable' established a comprehensive regulation of a highly concentrated and vertically integrated industry, with no role for competition at all. However, since the regime employed a fixed price–cap, any productivity gains accrued to the industry, and efficiency and financial health considerably improved during the following decade.[13]

[11] In Britain about three quarters of domestic coal output used to go into power generation, and three quarters of electricity was coal-generated. The shift to gas and cheaper imported coal lead to a sharp decline of the British coal industry, sealing the faith of the miners' once powerful trade unions. In 1989, 113000 miners produced more than 104 million tons of coal. Ten years later the workforce had shrunk to 16000 workers, producing 40 million tons.

[12] Centre for Economic Policy Research (2000), chapter 6, and VDEW (1999).

[13] See Centre for Economic Policy Research (2000), chapter 9 for further details. Green (1998) argues that welfare losses in market based dispatch systems will usually be be small.

Short term efficiency. There is no evidence that deregulation also improved short run efficiency. Summarizing the experience in a number of European countries, the Center for Economic Policy Research (2000) concludes

> ..the newly designed electricity systems have performed well technically, with the possible exception of access to the international transmission grid. The introduction of competition has not led to any system–wide crashes and it does not seem to have led to any deterioration in the quality of services, at least in isolated countries such as the United Kingdom, or those with a long experience of managing international trade, such as Scandinavia (p. 228).

So, reforms did not make things worse but they did not improve things either. Why is there so little scope for improving short run efficiency through markets? First of all, within a large vertically integrated utility, optimizing dispatch used to be challenging but fairly technical problem with little scope for rent seeking, hence of little interest to politicians or particular interest groups. As a result engineers could do their best to solve the complex problem, undisturbed by politically motivated interference. Second, the different types of power plants rely on rather mature technologies and the cost structures are well understood. Therefore, markets could not generate new information which would have improved the dispatch.[14]

Finally, due to the nature of electricity networks it is in fact difficult to replace 'authoritarian' dispatch within an integrated structure through a system of decentralized markets. Only the short run variable cost, largely determined by fuel–prices and fuel–efficiencies of the various plants, can be easily translated into a simple supply bid. The optimal dispatch, however, depends also on the different start up and ramping cost and the spacial interaction of real time demand and supply as it effects transmission losses and capacity constraints. In fact, given all the non–convexities and externalities in electricity networks, it would require a rather elaborate system of short term auction markets, with special provision for reserve capacity, transmission rights etc. to provide and process all the information which is necessary for an efficient dispatch.[15]

[14] These arguments apply to large vertically integrated firms. In Germany's highly fragmented system some small municipal power companies neither had the information nor the interest and expertise for optimal dispatch of their plant. Since the newly established power exchange provides public information about the cost of buying electricity on short notice, the small companies are now increasingly forced to compare the cost of own production to the prices at the whole sale market.

[15] While many issues of the efficient design of electricity markets are still unclear, it appears as if there is some trade–off between efficiency and competition. In order to stimulate competition the market should be 'thick' which requires simple contracts and a small number of separate markets. Hence it may be necessary to ignore some information (e.g. transmission losses) which would be helpful for minimizing cost, or to overinvest in transmission capacity. For an overview of issues in market design see Wilson (1998) and

Long term efficiency. The experience with market based systems is too short to judge as to whether they achieve long term efficiency.[16] Overcapacities in continental Europe justify the recent decline in investment and it would be premature to predict that there will be underinvestment and capacity shortages in the long run. In England, sustained market power of the incumbent generators lead, at least temporarily, to the opposite: excessive investment in new gas–fired plants. The location of new stations was also inefficient. As pool–prices did not reflect transmission losses or transmission constraints, new generators were build too far away from the centers of power consumption, putting additional strain on the transmission grid.

Hence, practical experience and economic theory suggest, that the creation of a complex system of short–term markets, day–ahead and hour–ahead markets for electricity, for reserve capacity and for transmission rights, does little to increase the efficiency of dispatch. What really matters for efficiency is the replacement of cost plus regulation of tariffs by fixed price regulation and a commitment to abstain from political interference. These two changes have yielded considerably improvements in medium term efficiency in a number of countries, with and without markets and competition.

3.3 Failing on Competition?

Vertical Separation and Short Term Markets.

The big stock and currency exchanges are probably the real world institutions which come closest to the theoretical model of a perfectly competitive market. The British model owes much of its appeal to the fact that it attempts to organize the exchange of power in a similar fashion. Unfortunately, when put into practice the results were not very impressive. Newberry & Pollit (1997) provide a detailed assessment of cost savings and the distribution of the gains from restructuring and privatization of the English power industry. Increases of labour productivity and the move to cheaper fuels resulted in a significant but fairly modest reduction of cost — in the range of 5%. However, all the gains were reaped by the shareholders of the new companies, because the price of electricity did not fall as much as the price of fuel or the reduction in other non–fuel cost. In spite of repeated interventions on part of the regulator to improve competition, the checks on market power were so poor, that taxpayers and consumers suffered substantial welfare losses, relative to the counterfactual (Newberry (2000)). Since only three independent generators emerged from the restructuring

Wilson (1999). For pricing of network access and transmission services see Chao, Peck (1996), Awerbuch, Crew, Kleindorfer (2000), Deng, Oren (2001)

[16] Again, theoretical analysis has pointed out, that due to the particularities of this industry, the usual trust in the efficiency of competitive markets is not warranted. See Bushnell, Stoft (1996) Wu, Varaiya, Spiller, Oren (1996) and Oren (1997) for some of the theoretical issues involved.

of the industry in the early 90th it is somewhat difficult to blame the design of the market for the lack of competition. One might argue that competition would have been much stronger with five or six players. However, in California generation capacities were distributed among seven companies, and the results have been even worse.[17] Due to the particularities of short term markets in vertically separated systems, it is in fact rather difficult to ensure competition.

Severe problems with short term electricity markets result from the fact, that the closer one gets to real–time dispatch the less responsive to price the demand becomes. In ordinary markets consumers will reduce and delay consumption or deplete stocks if prices increase, which in turn helps to keep any increases in check. However, in electricity markets these options are not available. Usually, consumers do not even know what the instantaneous cost of providing electricity are, which will change almost every minute. Since metering and billing is on a monthly or even annual basis, customers lack the knowledge and the incentives to adjust their consumption to the short cycles of the market. As a result, the system operator has little choice: either he buys electricity at any price to satisfy current demand or he cuts supply to certain areas, which is extremely costly in economic terms. This gives independent private generators a strong incentive to seek market power and to exploit it by bidding strategically.[18] Unfortunately the peculiarities of short term electricity markets provide them with ample opportunity to achieve this goal.

Since trading takes place on a daily basis in a transparent auction, generators can easily collude. Suppose they informally agree to bid prices well above their true cost, with the implicit understanding that if one party undercuts the others will retaliate. The gains from breaking this agreement are minimal. By underbidding its rivals a firm can sell its full capacity for one single day. The next day however everyone would know that the firm has cheated and the resulting price war would depress profits for a long time. Hence, it is in every firms interest to stick to the deal — at the cost of the customers.

Even if generators fail to cooperate, competition will be fragile. Suppose the largest generator has a market share of 20%, which is fairly small, and let him anticipate that at some peak hour during the next day, the reserve margin of the system will be 10%, which might be considered the minimum safety margin by technical standards.[19] Then his incentive

[17] A number of empirical studies have established substantial market power, both in England and in California. For England see Wolfram (1998), Wolfram (1999), and Wolak, Patrick (2001). For California: Borenstein, Bushnell, Wolak (2000) and Puller (2001).

[18] The incentives to manipulate spot prices are muted when deleviries are covered by long term contracts. In this case there are no immediate gains, though higher spot market prices will still raise the value of contracts in the future.

[19] Recall, that market share depends on the size of the market and therefore on transmission constraints. In California, for example, half of the power plants had to bee declared 'riability must run plants', that is plants which for which little alternative was available. For a more rigorous analysis of market power and

to abuse market power is substantial even if all other generators bid honestly their true marginal cost. Assume that the firm's capacity would be fully dispatched at the competitive price. Knowing that the system operator eventually has to buy at least half of the firm's capacity it has strong incentive to bid strategically. By raising its bid fourfold over the competitive price it can double its revenue and lower its cost since half of its capacity would be left idle. The optimal bid will not be determined by the firms marginal cost, but by its guess what the system operator perceives to be the social cost of blackouts. This happened in California's market for replacement reserve, a form of stand–by–power. Reserve power used to be bought at a regulated price of 10$. Upon deregulation, the price became highly volatile, sometimes being almost zero then jumping all the way up to 9999$/MW (apparently bidders were restrained only by their believe that the electronic system was restricted to four–digits bids).[20]

Curbing market power with price–caps?

It is sometimes claimed that one must not be too worried about competition, because, in the case, it does not work, the problem of market power can be fixed by introducing price caps. In fact, both, in Britain and in California it did not take long for the regulator to impose price caps on a supposed free short term market. Obviously, the need to introduce price caps destroys much of the appeal of short term markets. Moreover, price caps create as many problems as they solve.

Most importantly, it is not obvious at all at what level the price ceiling should be set. Consider again the Californian experience, after prices exploded in the free market, the regulator rushed to imposed a price–cap of 500$, which was tightened a couple of days later to 250$. This is a hefty 25 times increase over the previously regulated price and at the same time only a tiny 1/40 of the peak market price. Within half a year it was raised again to 750$. Why is it so difficult to find the right price cap? It is because in a short term market huge price fluctuations would be observed even if competition would be perfect. Most of the time, the price would be equal to the variable cost of the marginal plant dispatched. Such off peak–fluctuations would be moderate, but these prices would cover only the fuel cost of marginal plants. The fixed cost of providing the capacity, have to be recouped from price spikes during peak load, when capacity constraints become binding.[21] Hence the price cap during peak load will decisive for the investment in new capacity. If such a cap is needed because, almost by definition, competition is insufficient during peak load, then the amount

the role of transmission capacities see Stoft (1998), Bushnell (1998), Borenstein, Bushnell, Stoft (2000) and Joskow, Tirole (2000).

[20] See Wolak, Nordhaus, Shapiro (1998) and Bushnell, Wolak (1999) for more details.

[21] In electric power markets the simple rule for peak–load pricing has to be modified accounting for safety margins. This does not change the basic structure of the problem.

of new investment will always be politically determined. Unfortunately, the introduction of price caps changes the bidding strategies of the generators. Hence, the regulator can only guess how it will effect revenues be and has to continuously revise the cap in view of additional experience.

'Pay as you bid' instead of uniform pricing?

As Britain's regulators became increasingly frustrated by the lack of competition in generation they introduced a 'New Electricity Trading Arrangements' (NETA) abandoning the usual practice of uniform pricing in 2001. Under the old system all dispatched generators received the system marginal price, that is the highest offer accepted for a particular time. This gives large generators a strong incentive to submit exaggerated bids for their most expensive marginal plant. If the plant is dispatched they succeed in raising the market price and earn extra revenue on all plants. On the downside, they only forego small profits on their most expensive to run marginal unit if this is not dispatched for being too expensive.

Under NETA generators are payed their own bids when accepted. This should reduce the incentives of large suppliers to increase marginal bids strategically. They would run the risk of their marginal unit not being dispatched without having the gains of higher payments to intramarginal units. However, just as price caps, this is just another example of a 'quick fix' for a problem, which ignores the reaction of the players. Obviously generators will not follow their old bidding strategies, but raise their bids for intramarginal units closed to the estimated equilibrium price. Since there will be forecasting errors, the likelihood of inefficient dispatch will increase. In addition, when demand is unexpectedly low, the price might even be higher than under the old system. Hence, critics scold NETA to be a 'formula for inefficient production and higher prices'.[22] Furthermore, the new scheme plays to the disadvantage of small suppliers, for which it is more difficult to predict the equilibrium price than for large ones. Smaller new entrants will have to take more risks and see their profits decline. In the long run, this might even further weaken competition.

Negotiated Third Party Access: the Unlikely Success Story?

When Germany liberalized its electric power market for industrial customers in summer 1998, most observers remained deeply sceptical. With vertically integrated utilities left intact, no public regulation for the access to the grid, and no special agency to control market power, competition seemed doomed. Although tariffs for network access were complicated and had to be calculated for every transaction separately, bilateral trading of long term

[22]Wolfram (2000). In California similar proposals have been rejected. For an assessment see Kahn, Crampton, Porter, Tabors (2001).

Table 2: Selected grid access charges in 2001 [$/MWh]

	high voltage	medium voltage	low voltage
e.dis Energie	15,86	32,61	56,27
WEMAG, Schwerin	9,95	25,40	55,28
RWE - Net, (VEW)	8,56	19,76	40,45
Bewag, Berlin	12,05	21,01	35,66
E.ON, (Bayernwerk)	9,50	17,92	33,11
HEW, Hamburg	7,71	18,37	32,88
RWE - Net, (RWE)	9,23	14,69	26,43
Mainova, Frankfurt	11,02	19,26	25,09

contracts for bulk power developed fast. As large power producers were keen to expand into each others region, customers quickly found themselves in a strong bargaining position when their contracts came up for renewal. In some cases price cuts up to 50% have been negotiated. Since the terms of long term contracts are usually kept confidential, it is difficult to obtain an overall picture. According to estimates of the Verband der Industriellen Energie– und Kraftwirtschaft, VIK (Union of Industrial Power Users) average prices for industrial users fell by 25%–30%, from about 70 $/MWh in March 1998 down to 50 $/MWh in March 2000, with most of the decline occuring within a year after deregulation. The lack of transparency, resulting from bilateral trading, made collusion for the large generators difficult, thereby facilitating competition. When the Power Exchange in Leipzig (LPX) started operating in June 2000, next day's deliveries traded for an average price around 20 $/MWh, about half of the spot prices at the British Pool–market.

After a decade of decreasing fuel cost and improved efficiency the German electric power industry enjoyed healthy profit margins. It took only one year of competition for industrial customers to make hefty cuts into these monopoly rents. Prices declined in spite of continuing problems to ensure open and fair net–work access. As the figures in table 2 show access fees for customers with real time metering are high and vary substantially among different grid operators, the most expensive ones charging more than twice the price of the cheapest one.[23] This indicates that at least some grid–operators exploit their monopoly and it led the Bundeskartellamt (Federal Cartel Agency) to open an inquiry into the pricing policies of 22 grid operators. Low prices for power and high prices for network service is exactly what one would expect when vertically integrated firms shift cost from the competitive sector towards

[23] Access charges are calculated for commercial customers with real time metering. For details see VIK (2001)

the activity in which they enjoy natural monopoly. However, it can also be due to the fact, that prices for power are competitive while grid operators enjoy monopoly rents. Since in Germany, pure distribution companies are among those with the highest tariffs, there is in fact no clear evidence for inefficient cross–subsidization.

Since 2000 residential customers, and small commercial users, were also granted the free choice of their supplier. This time however the network operators managed to stifle competition with the help of an increasingly complicated tariff system and high charges for the use of the low voltage network. Nowadays, households have to select among a bewildering variety of tariff–schemes. Typically, the local incumbent alone will offer half a dozen tariff plans, with different combinations of fixed access charges, prices for consumption and contract durations. The consumer has to compare these with several dozens competing offers. However, all these new schemes, accompanied by heavy advertizement campaigns, largely failed to reduce the electric power bills, mainly because charges for the use of the low voltage distribution network turned out so high. Before liberalization, in January 1999, the Verband der Elektrizitätswirtschaft (VDEW) estimated for a typical houshold network services cost of 50 $/MWh and electric power cost of 58 $/MWh. In early 2001 residential customers' charges for grid–access have been estimated in the range of 72 $/MWh compared to 25 $/MWh for electric power itself.[24] Again it appears as if the lack of regulation has allowed grid operators to overcharge their customers.

4 Lessons for Russia?

More than a decade of international experimentation with various structures and designs of power markets has taught valuable lessons on how to increase efficiency and competition in the power industry. However, given the special conditions prevailing in Russia one must be careful when drawing conclusions from the experience in other countries. Most importantly, it has to be taken into account that Russia is still heavily subsidizing its power industry through low fuel cost, depreciation of capital stock and neglect of environmental damage. Hence tariffs are far below the long run social opportunity cost of providing electric power to customers. Unfortunately, this distortion of prices has implications for many questions, which at first glance may seem unrelated to the issue.[25] It is therefore useful to address the question of tariffs first before moving on to competition and investment.

[24] Haupt & Pfaffenberger (2001).

[25] In terms of economic theory, we are forced to judge economic policy in a 'second best environment' were intuition gained from 'first best' considerations is often misleading.

4.1 Tariffs

Tariff Level

The opportunity cost of providing electricity to Russian society are the lost revenues from selling fuel on world markets, the cost of labor, the environmental pollution, and the cost of replacing worn out capital. Measured against these cost, current tariffs for industry and households are far too low. The electric power sector survives only because it obtains fuel very cheaply, ignores environmental damage and invests very little. Given present overcapacities it is sufficient when tariffs are high enough to generate funds for repairs. In the long run, however, old equipment has to be replaced to maintain a capital stock large enough to satisfy demand with a comfortable safety margin. And even in the short run low tariffs induce Russian customers to waste energy with little benefit at home, instead of selling the fuel expensive abroad, or saving scarce resources for the future.

The only practical way to improve the energy efficiency is to increase tariffs. Such an increase is also needed to obtain a clear picture what capacity is truly needed in the power industry in the longer run. It is to be expected that even modest increases in tariffs will induce the Russian industry to become more energy efficient and prevent scarce funds from being wasted on investment in new capacity in power generation and transmission. Delaying the adjustment has long term structural effects as new investment is guided into sectors of industry, transport and agriculture which appear profitable only because they obtain power extremly cheap.

An increase of tariffs will create large windfall profits in the power industry, which might be unacceptable. Given the present ownership structure the government is entitled to a large share of the additional revenue. Nevertheless, it may be more straightforward to use taxation of fuel or electric power to skim off some of the profits. This would also strengthen the domestic tax–base.

Tariff Structure

In the Russian discussion of reforms it is often argued that cross–subsidization of residential users by industrial users is bad and should be abolished. This would require that tariffs for households should increase particularly fast to catch up with those for industry. Politicians are afraid of such unpopular measures and raise concerns about the hardships for poor people. However, given the present conditions in Russia the argument is in fact dubious.

It is a sound economic principle to charge every group of customers tariffs as close as possible to marginal cost. As it is more expensive to serve low voltage customers this would, in fact, require higher network fees and higher power tariffs for residential users. However, if one

has to deviate from marginal cost pricing for some reason, then the elasticity of demand has to be taken into account. The stronger demand responds to a change in price, i.e. the higher the price elasticity of demand is, the more important it is to stay close to marginal cost in order to minimize the efficiency loss from price distortions.[26] As a rule industrial users have a much higher price elasticity than residential users.[27] In Western countries, where prices are usually *above* marginal cost in order to recover fixed cost of capacity, tariffs for residential users should have a higher 'mark up' on marginal cost than those for the industry. In this sense households should subsidize the industry. However, in Russia the situation is opposite. Tariffs are far *below* marginal social cost. Hence, the problem is that, in response to low prices for power, firms increase energy consumption much more than private households. This is reflected in the fact, that, in spite of cross subsidization, the average power consumption of Russian households is only half of that of Western housholds, whereas industrial power consumption is well above comparable figures. From a purely economic point of view, it is therefore more important to keep industrial tariffs close to true economic cost, which are much higher than current tariffs. In other words, the current practice of cross–subsidization of residential housholds by the industry is efficient, given that tariffs in general are far too low.

Regulatory Commitment and Cost Incentives

International experience in a number of countries has shown that substantial reductions of fuel and labour cost can be achieved, if policy makers abstain from interference with business decisions and commit to tariffs, which do not appropriate the profits from improved efficiency. This requires a long term commitment from politicians to stick to a stable regulatory framework. The consolidation of regulation at the federal level has the advantage of making it more difficult for regional governors to influence the process and of making the regulation of fuel prices and power tariffs more consistent but it also carries the danger that tariffs will be kept low for fear of inflation. Such a policy would be doomed to fail, however, since partial price controls are a poor substitute for monetary discipline.

A commitment to a particular tariff schedule is difficult to achieve when unexpected external developments create large windfall profits, or losses which threaten the viability of the industry. Politicians would be forced to intervene and once this happens it is difficult to distinguish between profits (or losses) for which the industry should be held responsible for

[26] In economics this feature of optimally regulated prices is commonly referred to as Ramsey–pricing.

[27] Since demand pattern of the industry was not derived from cost minimization and households are still adapting their consumption to new opportunities it is difficult to judge price elasticities in Russia. It appears sensible to assume a price elasticity for industry somewhere at -1.5 and for residents between -0.8 to -1. This would roughly correspond to estimates for the USA in the early seventies, when a long period of cheap energy prices came to an end. See for example Chapman & Tyrell & Mount (1972).

and those which have been beyond their control. One possibility to decrease the need for intervention is a formula for the calculation of tariffs which already takes into account the most important external factors for the cost of the industry. Electric power tariffs should automatically be adjusted to the development of fuel prices, wage level etc. roughly in proportion to their contribution to total cost. Given the uncertainty regarding the development of relative prices, such a more complex formula can last for a longer period than a simple rule based only on inflation. In order to strengthen further the credibility of the schedule the regulator could strike a formal contract about the tariff formula lasting for three to five years. The power industry would then be entitled to damages from breach of contract if policy makers renege on their promises.

4.2 Competition and Market Structure

In most Western countries it was rightly taken for granted, that it would be good for society if monopoly rents are squeezed by opening the power industry for competition. The only disagreement was about how to achieve competition, given that bottleneck facilities such as the transmission and distribution networks are natural monopolies. Unfortunately, this presumptions may be wrong when prices are distorted as heavily as they currently are in Russia. If tariffs are already too low from the society's point of view and competition lowers them even further, incentives to use electric power efficiently will decline, hence economic welfare will decrease. The mark–up which a monopolized power industry can charge over competitive prices effectively acts like a tax. In other words, as long as fuel is subsidized, it might well be better to have monopoly profits in the electric power industry, rather than competition driving prices even further away from society's cost.

This is true not only for the overall level of prices for electric power but also for the structure of tariffs. As argued above, cross subsidization of residential consumption by industrial users is efficient under the present circumstances. However, competition will work to reverse this pattern for two reasons. First, even if both submarkets, for high voltage industrial users and for low voltage residential customers would be competitive, prices for residential users would be higher. This is because it is more costly to serve them and because their price elasticity is lower, hence they will be charged a higher mark–up to cover fixed cost. Second, a competitive wholesale market shall be established by summer 2002, but there are no concrete steps to develop competition in distribution. Moreover, international experience suggests that, if competition works at all, then it will be in the field of bulk power for high voltage customers not for residential customers. Hence, the result will be asymmetric: competition for industrial customers, monopoly for residential customers. Given the substantial overcapacities, large industrial customers will be able to obtain steep discounts, once they are entitled to choose their supplier. The energos, in turn, will attempt to raise

tariffs for residential and small commercial customers, to compensate for the loss in revenue. If the German experience is indicative, such a reversal may come about within a year or two. Hence, if the move towards competition in the power industry is to enhance economic efficiency, it will be necessary to reduce price distortions in the fuel sector very fast and to keep residential tariffs under separate regulation. In particular, price caps should not apply to 'baskets of tariffs' which would give energos the freedom to rebalance tariffs.

This critical assessment of competition under price–distortion is not to deny that competition has its virtues. The threat of loosing market share and profits puts pressure on the management of energos to increase operational efficiency and reduce cost, which are difficult to achieve through clever price–cap regulation alone. Market discipline would also help them to fend off political pressure of local governors. This leads to the question of how to develop competition, once the conditions are right.

The discussion in Russia has been influenced strongly by the Anglo-Saxon model of vertical separation and short term auction markets, which is still the long term goal of the reform plan. Experience has shown, however, that the complete separation of transmission and generation is neither necessary nor sufficient for competition. It misleads the attention of policy makers on problems related to short term efficiency, where little improvements are to be expected, and makes it difficult to curb market power and to commit to a simple and stable regulatory framework.

As the German experience shows, workable competition can be achieved even with integrated structures, provided that access to the high voltage grid can be assured. Once high voltage customers are allowed to choose their supplier the trade of long–term contracts for base load will develop fast. In order to ease this process, payments for access to the transmission grid should be simple even if this comes at the cost of incomplete reflection of temporary transmission constraints. Furthermore, the system operator should be under obligation to realize the transaction physically, except if this is technically impossible. In a sense, generators would have a right to inject similar to the right of customers to withdraw. In order to provide the system operator with enough flexibility he should have substantial peak—load generation capacity at his disposal either by ownership or by long-term contractual arrangements.

4.3 Investment

The leadership of RAO–UES has repeatedly claimed that its plans for reform, if implemented, will help to attract strategic (foreign) investors. However, this can be easily dismissed as wishful thinking. First, given the size of the installed capacity and the low efficiency of energy usage it is doubtful that much investment in new capacity is warranted. As argued above, a modest increase of real tariffs may reduce demand substantially and at

the same time generate enough internal funds to finance repairs and upgradings. However, in order to attract new entrants tariffs would have to be raised much higher, not only covering expenses for fuel, labour and repairs but also yielding a healthy profit margin on new investment. Such an increase would deliver huge windfall profits to the owners of existing capacities and appears extremely unlikely in the near future.

Second, *strategic* investors would be needed to implement new technologies, new organizational structures or new business practices. However, commissioning a power plant, transmission line, or transformator station are standard tasks which do not need a *strategic* investor. Such investors would be useful to improve management practice and increase operational efficiency, though the corporative turn around at RAO–UES shows that these goals can be achieved within the present structure. Given the current regulatory framework, any investor would have to be politically well connected, in order to protect his profits, which in turn raises concerns about insider deals at the stage of transfer of assets.

Finally, investment in power installations is highly ideosyncratic and of long duration. Hence, a stable business environment and protection against ex post exploitation of the investor are of outmost importance. The proposed restructuring is ambivalent in this respect. The consolidation of local energos may increase their ability to act as a reliable counterpart in long term contracts. However the dismantling of the mother company RAO-UES would remove one of the few players with a substantial standing in business. Moreover, the need to introduce a price cap on the short term market in a vertically separated system opens up a further inroad for political intervention.

This sceptical view is supported by the limited experience of new investment from deregulated industries. As explained in the previous section, in England, still serving as a blueprint for long term restructuring in Russia, new generators did not enter the market because it was competitive, but because the incumbents enjoyed market power and maintained a very high level of prices. Furthermore, the new, so called 'independent power producers', did not take the risk of selling into the volatile spot market. Instead, they formed closed alliances with regional distributors and perfectly hedged price risk for a period of 15 years. Long term contracts for fuel and electricity also protected them against the regulatory risk. Hence, if independent investment in new capacity is going to take place in Russia at all, it will be through long term contracts between RAO–UES, (or regional energos) buying the output, the (foreign) investor and Gazprom selling the fuel. Given the substantial risk of ex–post opportunistic behaviour, however, internal investment financed out of cash–flow is more efficient and will dominate the industry for a long time.

5 Conclusions

Initial proposals for the reform of the Russian electric power industry called for radical restructuring of the sector separating the network from power generation as it has been done in Britain and California. In summer 2001, however, the government endorsed a more gradual approach. In a first step control over dispatch and transmission grid is even recentralized in the hands of RAO–UES and by summer 2002 a second step shall establish a competitive wholesale market. While still an important long term goal, restructuring of RAO–UES has been deferred to a third step scheduled to be completed within another three years. It also planned to increase tariffs and to reduce cross–subsidization.

Many countries replaced cost–based regulation of tariffs by fixed price caps which do not directly depend on the cost of particular firms or plants. Under these schemes an increase of cost efficiency yields higher profits rather than a reduction in tariffs. This incentive stimulated cost cutting mainly in the areas of fuel supply and staff. However, protection against politically motivated interference with busines decisions and a credible commitment of the regulator not to appropriate efficiency gains is essential. Long–lasting price cap–formulas can achieve this, provided they take into account the most important exogeneous factors determining cost, such as inflation, fuel cost etc.

In Russia, tariffs for electric power, being subsidized through low fuel cost, are far below societies' opportunity cost. Furthermore, the political process of cost–based tariff setting destroys incentives for cost efficiency. Hence, the first priority must be given to a reform of the regulatory system and tariffs, in order to improve the incentives for cost efficiency and generate internal funds for investment. This requires two measures:

1. Regulation of tariffs should be in form of a price–cap, which is initially based on average cost of the industry — not on actual cost of particular types of suppliers or power plants. Instead of annual reviews, tariffs should be fixed in advance for a couple of years. Flexibility can be achieved by a fuel price escalator clause.

2. Tariffs for fuel and electricity should be increased substantially in order to bring them closer to true economic opportunity cost. However, contrary to what is often claimed, it is more important to raise tariffs for the industry than for residential users because the former have a larger price elasticity of demand.

There are two models for stimulating competition in the industry: a moderate one, obliging network operators to open their grid to competing generators on equal terms (third party access), and a radical one, solving potential conflicts of interest by separating transmission (and system operation) from generation.

Regarding competition in the wholesale market, the first approach performed better than expected. While grid–operators in Germany apparently abused the lack of regulatory oversight to raise transmission fees, there is little evidence that they favored expensive own power production over cheaper external supply. Once, prices on the wholesale market are competitive, such a strategy of crowding out more efficient suppliers would in fact make little economic sense. As a result, wholesale prices for long term contracts fell by about a quarter within a little more than a year after deregulation. Hence, workable competition on the wholesale market appears possible even with integrated structures.

The results of vertical separation and short-term markets, in contrast, are not very encouraging — to put it mildly. The British model, still serving as a blueprint for the long-term strategy in Russia, has recently been abandoned in its home country because the Government judged it to fail on yielding competition. And many observers of the Californian experiment are now convinced that a short term market will not operate efficiently unless real time metering and billing are available on large scale. The early enthusiasm for vertical separation and auction markets has vanished, giving way to a rather sober assessment of the virtues of radical designs in this complicated environment.[28] In order to prevent the abuse of market power in short term markets, demand has to be able to react to prices on short notice. One way to achieved this is real time pricing and metering of a sufficient number of large customers.[29] Market power can also be alleviated if buyers such as the system operator and distributers have direct access (either through ownership or long term contracts) to peak load generation capacity. Hence, complete vertical separation appears not desirable.

Competition in power generation would help to bring tariffs down. In Russia, however, this may even be counterproductive as fuel prices are still heavily distorted. Therefore, measures to stimulate competition should be taken carefully and only after a reform of the regulatory system and an increase of tariffs. Provided this groundwork has been done, international experience suggest that competition in the high voltage market can develop fast if:

1. High voltage customers are able to choose freely their supplier and to strike long term contracts.

2. The system operator has substantial peak—load generation capacity at his disposal either by ownership or by long-term contractual arrangements.

3. Payments for access to the transmission grid is simple even if this comes at the cost

[28] See among others Joskow (2000), Borenstein (2001), Borenstein, Bushnell (2001).

[29] This point makes perfectly sense in any electricity system. A substantial part of generation and transmission capacity is installed only for a few hours of peak consumption a year. If customers would face the full cost of providing electricity during this peak periods they would shift part of this consumption to off-peak periods. In a deregulated short term market this would have the additional benefit of limiting market power. In early 2001 California launched a large scale program to install devices for real-time metering and billing.

of incomplete reflection of temporary transmission constraints.

At present Russia has overcapacities even during peak load. Hence, in a competitive market prices would be pushed down to current short run marginal cost. This would generate enough revenues to recoup the cost of fuel but not to finance upgrading or replacement of equipment. It is only after further depreciation of the capital stock or a strong increase in demand will have lead to capacity shortages that prices will increase enough to attract new investment. Hence, in the short run opening the market for competition will make it more difficult to attract investment.

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6 Appendix

The following figures have been calculated from Brunswick Warburg (2000) and Brunswick Warburg (2001) and company data.

6.1 Energos

Energo	UES stake equity	UES stake votes	Capacity MW	Production Bln MWh	Purchase Bln MWh	Demand Bln MWh	av Tariff $/MWh
Altaienergo	53%	70%	812	3.1	6.2	7.6	10.2
Amurenergo	49%	60%	529	1.3	4.0	4.4	13.5
Arkhenergo	49%	59%	1,058	2.6	1.2	3.1	23.8
Astrakhanenergo	49%	49%	480	3.3	0.2	2.8	10.3
Bashkirenergo	21%	28%	5,064	24.5	−0.1	20.2	13.1
Belgorodenergo	49%	65%	65	0.2	11.8	9.9	12.3
Bryanskenergo	49%	65%	50	0.3	2.1	2.0	12.5
Buryatenergo	47%	47%	138	0.4	3.5	3.2	12.4
Chelyabenergo	49%	58%	1,879	10.0	11.2	17.9	13.1
Chitaenergo	49%	62%	508	3.2	1.4	3.8	15.1
Chukotskenergo			0		0.3	0.3	22.6
Chuvashenergo			2,222	4.3	0.8	4.1	10.0
Dalenergo	49%	65%	1,197	3.9	3.3	5.9	16.5
Dagenergo	51%	51%	1,365	3.3	−0.5	2.2	6.4
Ingushenergo			489	0	0.4	0.3	11.8
Irkutskenergo	0%	0%	12,920			36.2	
Ivenergo	49%	56%	683	1.4	3.0	3.6	14.1
Kabbalkenergo			33	0.1	1.3	1.2	15.3
Kalmenergo			1	0	0.6	0.5	13.9
Kalugaenergo	49%	49%	6	0.0	4.0	3.4	11.5
Kamchatenergo	49%	59%	430	1.5		1.2	58.5
Karcherkesskenergo			0	0	1.1	0.9	11.7
Karelenergo	100%	100%	915	3.9	3.8	6.2	10.1
Khabarovskenergo	49%	61%	1,973	8.2		5.4	17.0
Khakassenergo			270	0.9	5.5	5.3	4.0
Kirovenergo	49%	64%	940	3.6	3.4	5.7	14.8
Kolenergo	49%	65%	1,928	8.5	4.7	10.7	7.8
Komienergo	49%	49%	758	3.1	2.6	4.6	17.8
Kostromaenergo	49%	65%	215	1.1	1.7	2.3	13.3
Krasnoyarskenergo	51%	66%	2,075	10.7	25.2	27.6	7.4
Kubanenergo	49%	49%	932	6.2	7.9	12.2	14.2
Kurganenergo	49%	54%	480	1.2	3.6	3.9	13.8
Kurskenergo	49%	60%	197	0.9	5.6	5.4	11.8
Kuzbassenergo	49%	49%	4,750	26.6	4.6	26.6	9.2
Lenenergo	49%	57%	3,253	16.1	10.7	21.4	11.8
Lipetskenergo	49%	49%	543	1.9	6.9	7.3	13.0

Energo	UES stake equity	/ votes	Capacity MW	Production Bln MWh	Purchase Bln MWh	Demand Bln MWh	av Tariff $/MWh
Magadanenergo	49%	64%	747	0.3	2.0	1.9	13.2
Marienergo	60%	72%	195	0.8	1.6	2.0	12.4
Mordovenergo	49%	49%	355	1.0	1.9	2.3	15.4
Mosenergo	51%	51%	15,010	68.9	–1.5	51.1	13.6
Nizhnovenergo	49%	62%	1,271	6.0	11.3	14.5	15.1
Novgorodenergo	49%	63%	190	0.9	2.3	2.6	13.1
Novosibirskenergo	13%	16%	2,537	12.3	0.0	9.9	10.6
Omskenergo	49%	60%	1,655	6.2	1.9	6.6	13.5
Orelenergo	49%	60%	336	1.3	1.8	2.5	10.3
Orenburgenergo			3,425	15.9	–2.8	10.4	11.8
Penzaenergo	49%	60%	375	1.1	3.2	3.6	13.4
Permenergo	49%	64%	2,008	9.9	9.4	15.9	14.3
Pskovenergo	49%	49%	13	27.0	1.7	1.5	15.4
Rostovenergo	49%	64%	1,144	3.4	8.8	10.4	13.2
Ryazanenergo	49%	49%	100	0.3	4.0	3.6	13.4
Samaraenergo	49%	56%	3,495	14.5	6.4	17.0	13.1
Smolenskenergo	49%	59%	1,042	2.6	1.5	3.3	13.8
Sakhalinenergo	49%	49%	619	2.0		1.4	20.4
Saratovenergo	49%	64%	1,502	4.2	6.8	9.0	13.2
Sevkavkazenergo			78	0.3	1.2	1.3	10.3
Stavropolenergo	54%	71%	477	1.4	5.9	6.1	13.6
Sverdlovenergo	49%	65%	1,827	38.8	0.6	32.5	13.3
Tambovenergo	49%	56%	315	1.2	2.8	3.3	12.9
Tatenergo	0%	0%	7,056			17,3	
Taimyrenergo			1,041	4.3	0.7	4.0	4.3
Tomskenergo	49%	57%	421	1.6	3.7	4.4	10.9
Tulaenergo	49%	49%	1278	3.5	6.1	7.9	11.8
Tverenergo	49%	65%	308	1.3	3.9	4.2	14.1
Tyumenenergo			10,421	61.87	–0.9	44.5	13.2
Udmurtenergo	49%	55%	492	2.3	4.9	6.0	12.5
Ulyanovskenergo	49%	65%	862	1.7	3.8	4.5	14.0
Vladimirenergo	49%	49%	407	1.9	4.3	5.1	13.2
Volgogradenergo	49%	61%	1,757	3.6	10.0	10.8	13.2
Vologdaenergo	49%	49%	665	3.2	7.3	8.6	15.8
Voronezhenergo	49%	65%	155	1.0	7.4	7.0	13.3
Yakutskenergo	49%	58%	1,695	7.3	–1.0	4.8	20.7
Yantarenergo			134	0.1	2.6	2.2	16.6
Yarenergo	49%	64%	611	2.4	4.4	5.6	13.6

6.2 UES–Plants

Station	Type	UES stake	Capacity MW	Production Bln MWh	av Tariff $/MWh	Cash cost $/MWh
Beriozovskaya GRES-1	Coal	100%	1,600	6.9	6.4	4.7
Cherepetskaya GRES	Coal	56%	1,425	2.8	20.1	17.9
Gusinooziorskaya GRES	Coal	100%	1,260	2.5	13.4	11.1
Kamskaya GES	Hydro	100%	483	1.7	3.3	2.4
Kaskad Verhnevolzhskikh GES	Hydro	100%	440	1.1	2.9	1.9
Kharanorskaya GRES	Coal	100%	215	1.1	13.7	11.1
Kirishskaya GRES	Oil	100%	2,097	2.8	14.8	9.0
Konakovskaya GRES	Gas	51%	2,400	7.6	10.2	7.5
Kostromskaya GRES	Gas	51%	3,600	11.6	8.7	6.4
Krasnoyarskaya GRES-2	Coal	100%	1,250	3.9	7.3	6.1
Nevinnomysskaya GRES	Gas	100%	1,340	7.0	8.6	6.9
Nizhegorodskaya GES	Hydro	100%	520	1.4	1.8	1.0
Novocherkasskaya GRES	Coal	100%	2,245	7.2	11.2	10.8
Novosibirskaya GES	Hydro	100%	455	1.6	1.6	1.5
Pechorskaya GRES	Gas	51%	1,060	3.0	8.0	6.9
Permskaya GRES	Gas	100%	2,400	8.4	7.1	6.2
Primorskaya GRES	Coal	56%	1,495	4.1	9.8	12.8
Pskovskaya GRES	Gas	50%	430	2.4	6.4	5.7
Reftinskaya GRES	Coal	100%	3,800	21.3	8.5	6.9
Ryazanskaya GRES	Gas/Coal	100%	2,720	9.3	11.2	9.3
Saratovskaya GES	Hydro	100%	1,360	5.5	1.4	1.1
Sayano-Shushenskaya GES	Hydro	79%	6,721	24.7	1.2	0.5
Sredne-Uralskaya GRES	Gas	100%	1,216	3.4	8.9	5.8
Stavropolskaya GRES	Gas	51%	2,400	9.8	8.6	7.4
Troitskaya GRES	Coal	100%	2,059	4.2	11.7	11.3
Verkhne-Tagilskaya GRES	Gas/coal	100%	1,521	5.4	14.1	7.9
Volzhskaya GES (Volzhsky)	Hydro	84%	2,541	11.6	1.4	0.9
Volzhskaya GES (Zhigulevsk)	Hydro	83%	2,300	9.8	2.9	1.7
Votkinskaya GES	Hydro	60%	1,020	2.5	2.1	1.3
Zeyskaya GES	Hydro	56%	1,330	5.6	3.2	1.5
Total			53,703			