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SGEM research report

WP 5: Market development in different countries
Task 5.3.1.: Market development in the Russian energy market

Dmitry Kuleshov
Lappeenranta University of Technology
LUT Energy

Lappeenrannan teknillinen yliopisto
Lappeenranta University of Technology

www.lut.fi

PL 20/P.O. Box 20
FI-53851 Lappeenranta

tel +358 5 62 111
fax +358 5 621 2350

Y-tunnus 0245904-2
ALV/VAT FI 02459042

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Acronyms

TGC Territorial Generating Company

WGC Wholesale Generating Company

SO System Operator

ATS Administrator of the Trade System

SFT Sector of Free Trade

HHI Herfindahl–Hirschman Index

LMP Local Marginal Price

OTC Over-the-Counter

UES United Energy System

FTS Federal Tariff Service

ROR Rate of Return

IRR Internal Rate of Return

WACC Weighted Average Capital Cost

CAPEX Capital Expenses

OPEX Operational Expenses

1 Introduction

Deregulation of the power industry in Russia has created incentives to invest in the Russian generation allowing it to escape from wasteful operation in times of monopolies and turn into profitable enterprises. However, many risks appeared during the power industry reform and after market opening that had not been known before. This paper doesn't tend to answer the question if there is much to gain from investing in the Russian power or not. Instead, its purpose is to give an explicit description of potential risks an investor in power generation could meet if he decides to operate in the power market of Russia.

The paper is organized as follows. It starts out with brief introduction of the current electricity and capacity markets structures formed in result of the power industry reformation. Then the most important risks for a player which operates in the wholesale market of Russia are revealed. The paper draws much attention to the market risks and includes examination of hedging instruments available for the market participants at present. A number of examples of hedging are introduced for the purpose of disclosure of merits and demerits of these instruments.

The rest of the paper is devoted to the issue of capacity market functioning in Russia. For the generating companies in Russia sale of their capacity takes up a half of their total revenues. Thereby, for the investor in the power generation in Russia it is important to understand how to operate in this sector of trade and avoid significant risks related to the choice of wrong strategy of the capacity market participation. In this part of the paper, the different mechanisms of capacity sale which are available in the market for a generator are demonstrated and the risks related to each of the mechanisms are revealed. This also includes estimation of possible monetary revenues and losses that the owner of new generation sets in Russia could get from the market depending on forecast alternatives

2 The Russian Power Sector

2.1 A survey of the energy reform

The main goal of the energy reform which started in Russia in the latest 1990's was to attract massive internal and foreign investments in the weakened power sector and create a competitive market environment in sphere of energy production and sales. The restructuring process of the industry was organized between 2003 and 2007 years. During this period all assets of the regional monopolies were split out and then gathered together in accordance with their predestinations into generation, transmission and distribution and sale companies. The main regulation when the generation assets of the monopolies were dividing between the newly formed private generating companies was that each of these companies could not own more than 35% of capacities in the first (European) and the second (Siberia) price areas of the future wholesale market. In result of that, 14 Territorial Generating Companies (TGC) operating both heat and energy production and 6 Wholesale Generating Companies (WGC) producing energy only were created. The WGCs pool most of the thermal power stations of Russia located in different parts of the country. In turn, the TGCs are created on a basis of cogeneration and hydro stations located within the specified territories of Russia. Some of the TGCs also operate thermal power stations.

All nuclear power plants and the majority of the hydro stations in Russia remained under control of the state companies "EnergoAtom" and JSC "Rus-Hydro. The functions of dispatching service were entrusted to the independent System Operator (SO). The JSC "Federal Grid Company of Russia" runs the grid at the national level and the JSC "MRSK-Holding" is responsible for the distribution of energy in the regions. Monopoly on the cross-border trade belongs to the JSC "Inter RAO" in which around 60% of assets belong to the concern "EnergoAtom"

In 2001 the commercial operator (ATS) responsible for all electricity trade organization was found. Following that, the first attempt to introduce market relationships in the power industry was undertaken. The Sector of Free Trade (SFT) opened on 1st of November 2003 in European part of Russia and on 1st of May 2005 in Siberia, allowed producers to sell correspondingly 15% and 5% of their output and purchasers to buy 30% and 15% of their consumption at deregulated prices. This market existed to September 2006 when the Decree No 529 "On Improving Operations of the Wholesale Electricity (Capacity) Market" was approved by the Russian government. Acceptance of the decree meant launching of the competitive power markets of transient period in Russia. The term "transient period" here indicated that the process of the market opening would be implementing gradually between 2006 and 2011 years. For that purpose, the decree stated the annual rate of market liberalization 15-20% according to which more and more power must be sold and purchased every year at deregulated prices. Thereby, according to the reform schedule the market will become fully deregulated after 1st of January 2011. A distinctive feature of the Russian power market is that there are two commodities- electrical energy and capacity- traded in separate markets. Organization of each of the markets will be considered later in more details.

2.2 Power sector performance

At present, the total power generation capacity of the country 215.1 GW has the following structure: 67.6% of heat capacities, 21.3% of hydro capacities, 10.9% of nuclear capacities and 0.2% of capacities using renewable sources of energy (GenPlan 2010). Specifically, WGCs pool 31 power stations most of which are thermal plants of the total capacity 53.9 GW and TGCs ingress cogeneration and hydro plants of the total capacity 55.6 GW. The JSC "Rus Hydro" runs 21 hydro stations with the total capacity 25.5 GW and the OJSC "Rosenergoatom Concern" exploits 10 nuclear plants of the total capacity 24.2 GW (RusHydro 2010), (EnergoAtom 2010). The rest of the capacities belong to the companies operating outside the wholesale market.

The property of the FGC includes 121096 km of lines and 797 substations (FGC 2010). The number of distribution companies, including municipal companies, is close to 1000. The total length of distribution networks is 2.1 million km (MRSK 2010).

Russia consumes annually about 1023 TWh of electricity including 117 TWh consumed by residential sector (YearBook 2009). The number of big industrial consumers buying energy and capacity from the wholesale market is 40 and the number of retailers is more than a hundred.

3 Physical markets of energy

3.1 Day-ahead market

In many markets, day-ahead is an important point of time. By that time, participants have a significant amount of information in relation to both production and consumption. Retailers will know with some certainty what their own customer demand is likely to be and generators will have a good understanding of the plant on the system at present, and the likely schedule of plant operation for the next day (Frontier 2005).

Day-ahead markets differ whether they apply zonal or nodal price formation. The zonal price formation implies organization of the common auction of suppliers' and purchasers' offers and establishment of the single equilibrium price for all market participants as a result of supply and demand curves intersection. This approach is widely used in the markets with sufficient amounts of transmission capacities. For instance, most of the European markets apply zonal price formation with the common system price for energy in scales of one or several countries. However, application of the single equilibrium price for the whole market in Russia was found difficult due to very different costs of generation in regions of the country, high rate of networks branching and presence of network congestions. Owing to that, it was decided to utilize the nodal price method in determination the competitive energy prices in the day-ahead energy market of Russia. In contrast with the zonal price formation approach, this method implies establishment of different prices in locations of the market participants called nodes.

The commercial Operator runs the day-ahead market in consort with the System Operator. Based on notifications from generators about their possible maximal/minimal volumes of production and own forecast of power consumption, the latter defines feasible modes of the power system and decides generators to produce, and then sends the data to the Commercial Operator. In turn, based on the information obtained from the SO and participants' offers, the Commercial Operator conducts the marginal auction and defines prices and volumes of production and consumption in the market. For all this, the equilibrium prices at nodes are defined by the Commercial Operator in such way to maximize amounts of hourly production and consumption and bring into play all volumes of generation with the lowest prices, volumes of consumption with the highest prices and volumes containing in price accepting offers. The resultant equilibrium price at the sink node should not exceed price offer of the purchaser at that node which volume was included in trade schedule. Exactly, equilibrium price at the node of generation should not be lower than price offer of the generation set at this node.

The market participants must submit to the Commercial Operator their price offers not later than 13.00 the day prior the day of energy delivery. The price offers of two types are allowed: non-integral offers containing 24 sub-offers and integral offers for 0-9 and 10-23 hours of the next day. Each of sub-offers of generators contains three "price-volume" stages and one additional price accepting stage in regards to a technical minimum of production. Sub-offers of consumers also include three "price-volume" stages and one price accepting stage in regards to amounts of energy in their long-term contracts. (Market Council 2011a)

Practically, submission of price accepting stage in an offer is important part of bidding as it influences on inclusion or non-inclusion of the participant in trade schedule. During auction, the Commercial Operator triggers price accepting offers of generation units in the following order: *firstly* included offers of stations that provide system reliability, nuclear power plants and plants operating at technical minimum of production, *secondly* included offers of heat stations operating in heating regime only and hydro stations producing energy by technical necessity, *thirdly* included offers of generators submitted with respect to amounts of energy in their regulated agreements, *fourthly* included offers of generators submitted with respect to amounts of energy in their forward agreements, and finally, *fifthly* included offers of other generators. In similar way the Commercial Operator sets the priorities for price accepting offers of consumers *firstly* including offers of consumers with respect to amounts of energy in their regulated agreements, *secondly* including offers of consumers with respect to amounts of energy in their forward agreements and *thirdly* including offers of other consumers.

The advance premium in the day-ahead market is committed on 14th and 28th day of the settlement month. The final settlement is organized on 21st day of the month next to a settlement period. (Market Council 2011b)

3.2 *Balancing market*

Following any formal day-ahead market, during intraday trading participants continue to fine tune their positions in the light of new information about their own production and consumption position and also the overall system position. In that sense, intraday trading may be viewed as an extension of day-ahead fine tuning (Frontier 2005).

In Russia intraday trading of energy is organized in the balancing market. The System Operator runs the market independently using the model of the day-ahead market. For the purposes of formation the balanced modes of production and consumption for each hour, the SO organizes competitive auctions of offers of the market participants eight times per one trading day. Only generators and consumers with regulated load are allowed to participate in auctions for system's balancing. During auction, the SO uses the same price offers of generators that they made in the day-ahead market and offers of consumers with regulated load submitted not later than 17.00 on previous day. Participants also have an opportunity to submit "quick" price accepting offers for changes of production and consumption 210 minutes as latest before an auction (Market Council 2010c). In result of auctions, the SO forms schedule of the balancing market for next three hours defining amounts of deviations (dispatching volumes) caused by internal and external incentives of participants and equilibrium prices of deviations (indicators) at nodes. As well as in the day-ahead market, the value of indicator can not be lower than price offer of a generator at his node and higher than price offer of a consumer with regulated load at his node.

The prices of deviations at nodes depend on types of incentives that caused these deviations. For instance, if a generator fails to produce scheduled amount of energy at an hour, he purchases amounts of his underproduction in the balancing market at the highest value from day-ahead market price, indicator of balancing market and his price offer submitted in the day-ahead market. Similarly, if he makes overproduction at his own fault, he sells an amount of deviation at the lowest value from day-ahead market price, indicator of balancing market and his day-ahead market price offer. However, deviations of generator's production caused by external incentives which may arise as a result of discharge of orders obtained from the SO are billed differently. Overproduction by external incentive is sold in the balancing market at the highest value from indicator and price offer in the day-ahead market, and underproduction is purchased at the lowest value from indicator and price offer in the day-ahead market.

The generators submitted "quick" price accepting offers pay off deviations caused by external incentive at indicator's price. Up-deviations caused by internal incentive of a producer are sold at minimal value from indicator and day-ahead market price, and down-deviations caused by internal incentive are purchased at maximal value from indicator and day-ahead market price.

Table 1 Prices of deviations in the balancing market (CARANA 2005)

Incentive type	Suppliers with price offers	Suppliers without price offers and suppliers with "quick " price accepting offers	Consumers with regulated load
External, up	Max (indicator, price offer)	Indicator	Min (indicator, price offer)
External, down	Min (indicator, price offer)	Indicator	Max (indicator, price offer)
Internal, up	Min (indicator, spot price, price offer)	Min (indicator, spot price)	Max (indicator, spot price, price offer)
Internal, down	Max (indicator, spot price, price offer)	Max (indicator, spot price)	Min (indicator, spot price, price offer)

There is no inducement of a generator to withhold his capacity from trade in the day-head market in favor of the balancing market. The price of deviation caused by internal incentive in the balancing market is always less beneficial that the price of deviation caused by external incentive. The purchase price in the balancing market can not be more advantageous than in the day-ahead market.

4 Identification of risks in the Russian energy market

4.1 Market risks

Transition of the Russian power industry form monopoly and creation of the markets of energy and capacity was carrying out gradually within 5 years. Thereby, risks of operation in the markets were also increasing gradually. For instance, during the first year of energy market opening, *market risks* stipulated by changes of electricity prices and sale volumes due to weather conditions, demand fluctuation, types of selected generating equipment and bid strategy of suppliers and buyers were relatively small as only insignificant volumes of electricity were allowed to trade at deregulated prices. However, at the proceeding of the reform more and more volumes of energy have being offered to the competitive market and the risks of operation in the market became higher. The market risks and opportunities of their mitigating will be discussed in details in chapter 5.

4.2 Legislation risks

During the transient period of the market 2006-2011, the market rules were constantly changing as regulators were trying to find the optimal market model that better fits the Russian power industry structure correcting previous mistakes of the reform, eliminating market abuse and destroying problems of cross-subsidiary between different parties of industry. For instance, after several cases of large-scale speculations by means of the energy forward contracts, the regulators introduced temporary obligations for the market participants to corroborate volumes under these contracts with real production and consumption. Also, during the crisis 2008-2009 when the volumes of energy consumption decreased to a considerable scale and big consumers in the retail market managed with the volumes supplied at regulated prices only, the regulators made amendments to the market rules and obliged these group of end-users to pay off larger share of their energy consumption at higher deregulated prices. These risks are often defined as *legislation risks*. Another form of their manifestation in the Russian power market is introduction of *price smoothing* in the spot-market. This mechanism is applied by the regulators at times of significant spot-price increase over a lengthy period of time. According to this mechanism, the regulators detect the generators which have submitted the highest price offers to auction. Then they reduce the prices in their bids and run auction again keeping the volumes of production in the bids unchanged. As a result of this procedure the average market prices go down to the previous level.

4.3 Risks of payment default

Other risks that constantly present in the power market of Russia are the risks of consumers *payment default*. These risks arise as a result of low responsibility for non-payments in the market. The point is that, historically, an attitude of consumers to electricity was like to a commodity that will be delivered in any case. The costs of energy were always included in fixed costs of enterprises, factories and plants. When markets have opened many consumers got excessive average energy fee and their revenues became reduced. That caused delays and interruptions of payments to the generating companies as consumers attempted to keep the level of profits which they had had before deregulation of the power industry by saving on energy payments. In addition, until recently there has been absence of system of financial guarantees when a generator and a customer entered into a bilateral OTC agreement. Also, an order of payments for nodal price difference at the moment of bilateral contracts' execution was not clearly defined.

The system of regulated contracts called for adaptation of industry to the market environment and mitigating of market risks on one hand, has brought risks of non-payments from another. The fact is that, regulated agreements obliged stations to produce and sell power to concrete consumers chosen by the Federal Tariff Service some of those were not trusty in issue of payments for energy. This especially refers to retail suppliers of last resort which are the main sources of debts. The point is that they can not be cut off in energy supply because of the population among their end-users.

On the other hand a centralized system of accounts is organized in the spot-market in which a purchaser is not allowed to choose what generation he wants to pay off in the first place. This system provides reduction of debts, but on the other hand the debts of some market participants become equally spread out on the others in form of cost unbalance. Accumulation of debts leads to a problem of expenditures covering in generating companies and doesn't allow them to attract necessary loan proceeds.

4.4 Operational risks

Operational risks stipulated by weak organization of management in sphere of electricity and capacity realization, in turn impeded getting of full possible revenue from the market. These risks claim for creation of developed system of risk-management in companies. However, in many energy companies the system of risk-management has not been developed in proper way.

4.5 Risks of market concentration

The Russian power market is oligopoly with presence of tens huge generating companies that drives energy prices in their domains of activity. In fact, emergency of this market form is explainable in view of the existing transmission grid topology in Russia. The point is that historically, generation has always been constructed closely to industrial load centers and transmission capacities between different industrial areas were mainly planned to be used as reserve lines. This explains splitting of the power market in Russia into numerical regional market areas free from transmission congestions inland.

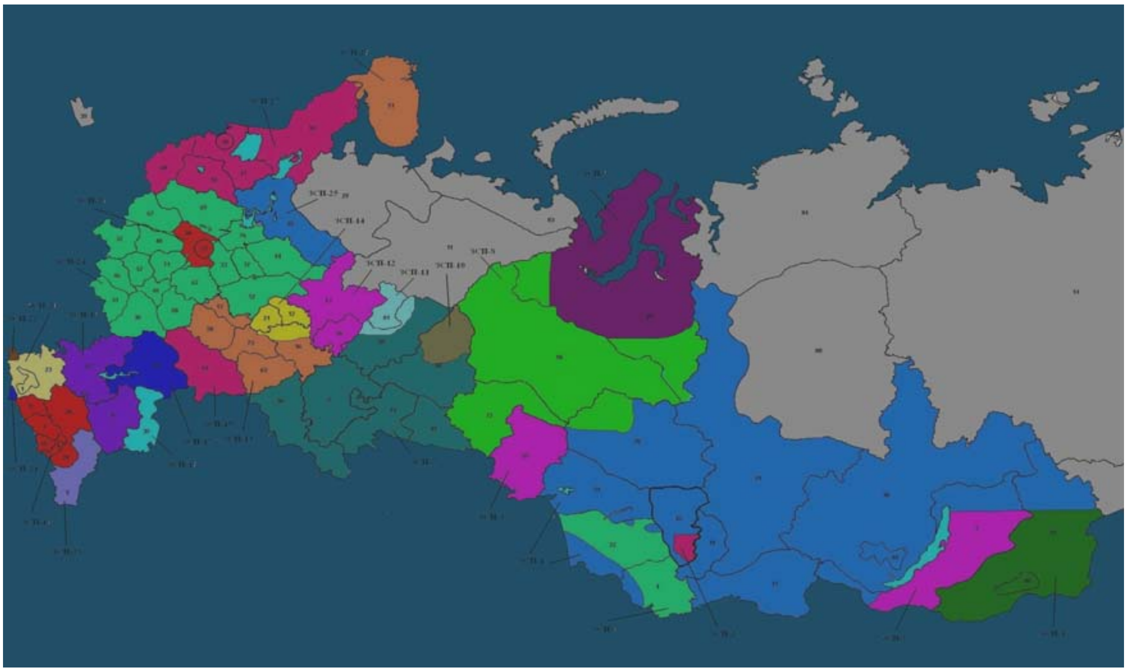

Figure 1 Areas free of transmission congestions in the power market of Russia (Kataev 2008)

With the exception of several companies, each of 14 territorial generating companies created in the course of the power reform operates within one or more areas of free power flow and almost completely determine the price of generation in these areas. In fact, there are only few large areas of free power flow (areas with no transmission congestions) where the market concentration is low.

Figure 2 Areas of activity of the Territorial Generating Companies in Russia (RAO UES 2006)

The tables 2-3 below reveal the levels of participants' concentration in the power market of Russia measured by Herfindahl–Hirschman Index (HHI). The values of index higher than 0.18 denote high levels of market concentration

Table 2 Herfindahl-Hirschman Index of producers' concentration in the power market of Russia (Trachuk 2010):

Area of free power flow	HHI	Area of free power flow	HHI	Area of free power flow	HHI	Area of free power flow	HHI
1	0.244	8	0.304	15	0.428	22	1
2	0.576	9	1	16	0.556	23	0.973
3	1	10	0.735	17	0.593	24	0.204
4	0.6	11	0.536	18	1	25	0.913
5	1	12	0.355	19	0.384	26	0.632
6	0.487	13	0.348	20	0.624	27	0.494
7	0.178	14	0.428	21	0.618	28	0.501
1st price area: HHI=0.132							
2nd price area: HHI=0.191							

Table 3 Herfindahl-Hirschman Index of consumers' concentration in the power market of Russia (Trachuk 2010):

Area of free power flow	HHI	Area of free power flow	HHI	Area of free power flow	HHI	Area of free power flow	HHI
1	0.295	8	0.637	15	0.376	22	0.466
2	0.214	9	0.986	16	0.608	23	0.966
3	0.621	10	0.323	17	0.370	24	0.107
4	0.601	11	0.669	18	0.723	25	0.745
5	0.755	12	0.654	19	0.300	26	0.903
6	0.540	13	0.309	20	0.389	27	0.284
7	0.296	14	0.331	21	0.649	28	0.774
1st price area: HHI=0.112							
2nd price area: HHI=0.226							

New integrations of generation and sale companies (IES-Holding, Gazprom, SUEK, LUKOIL) could restrict competition by demand and create risks of vertical integration. The level of concentration of these companies in the areas of free power flow is presented in the table 4.

Table 4 Market concentration of the companies integrating generation and sale assets (Trachuk 2010)

Area of free power flow	HHI	Area of free power flow	HHI	Area of free power flow	HHI	Area of free power flow	HHI
1	0.259	8	0.352	15	0.232	22	0.367
2	0.262	9	0.498	16	0.300	23	0.491
3	0.788	10	0.308	17	0.328	24	0.105
4	0.351	11	0.559	18	0.851	25	0.439
5	0.727	12	0.549	19	0.185	26	0.755
6	0.282	13	0.166	20	0.272	27	0.220
7	0.152	14	0.298	21	0.319	28	0.344
1st price area: HHI=0.106							
2nd price area: HHI=0.195							

5 Hedging instruments on the Russian Market of energy

5.1 Forward contracts

In many power markets, participants usually hedge a significant part of their production and purchase volumes via bilateral contracts leaving relatively small volumes of energy exposed to the risks of price fluctuations in a spot-market. This is especially true for retailers which charge their end-users with fixed tariffs for electricity and big industrial consumers interested in getting of stable proceeds of activity. In these circumstances, a conclusion of a forward agreement is the most favorable and simple way to hedge price for the future supplies of energy. However, it will be shown later that forward contracts for energy in Russia due to their contestable effect and complexity are not being used much by the market participants. According to the estimations of the "Moscow Energy Exchange" carried out at the end of 2009 energy trade via forward contracts took up the share of only 8% from the total market turnover (ARENA 09).

Forward contracts or sometimes called "contracts for difference" are agreements with fixed price of energy concluded between sellers and buyers for the purposes of hedging against undesirable prices changes in the spot-market. Usually, spot-prices for electricity are very volatile. This is a consequence of the inability to store electricity at any significant scale, so that consumption and generation need to match each other very closely (Anderson 2006). Electricity demand is varying at the proceeding of day due to weather conditions and load changes leading to price spikes. The other factors affecting spot-prices are unexpected transmission constrains, unplanned repairs, and fast changes of generation structure.

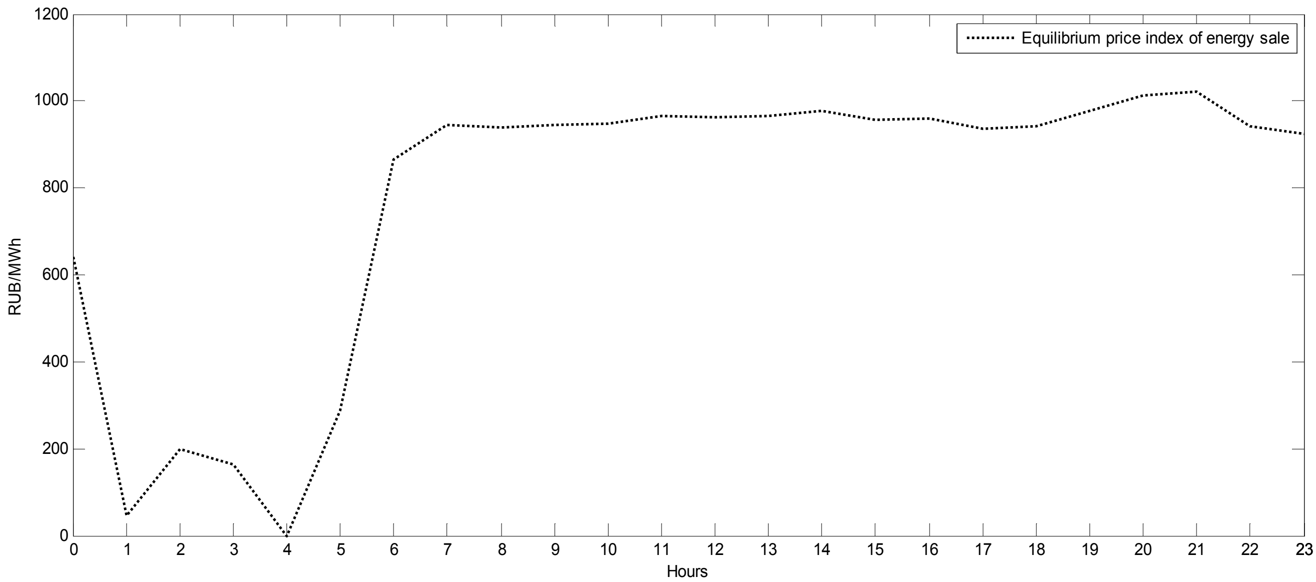

Figure 3 Example of average day-ahead prices for energy sale in UES "South" (Operation day 23.09.2010).

Along with that, there are several specific factors influencing the spot-prices in the power market of Russia. For instance, for the producers of energy there exists the risk of zero spot-prices appearance (see Figure 3). These prices could take place during the special "forced" regimes of the UES operation which are introduced by the SO to provide reliable work of the power system. According to the market rules, generators are allowed to submit three step increasing bids for their volumes of production and one price accepting bid in regards to the technical minimum of their station's output. The price accepting bids also could be submitted by the hydro stations in regards to energy volumes, production of which is caused by the technical necessity (spring floodgate). Thereby, during these regimes there might be a situation when the SO let the technical minimum of generators pass to a bid auction only. That causes appearance of zero-prices on the market. Sometimes these prices are also the result of the transmission congestions which block power flows from the areas with low price generation. On the other side, possible revenues of the energy producers from the spot market could be artificially reduced by application of a price smoothing mechanism. This mechanism is introduced by the regulators in cases of intensive increase of average market prices above the maximum price level defined on a basis of statistical data over the previous periods of time.

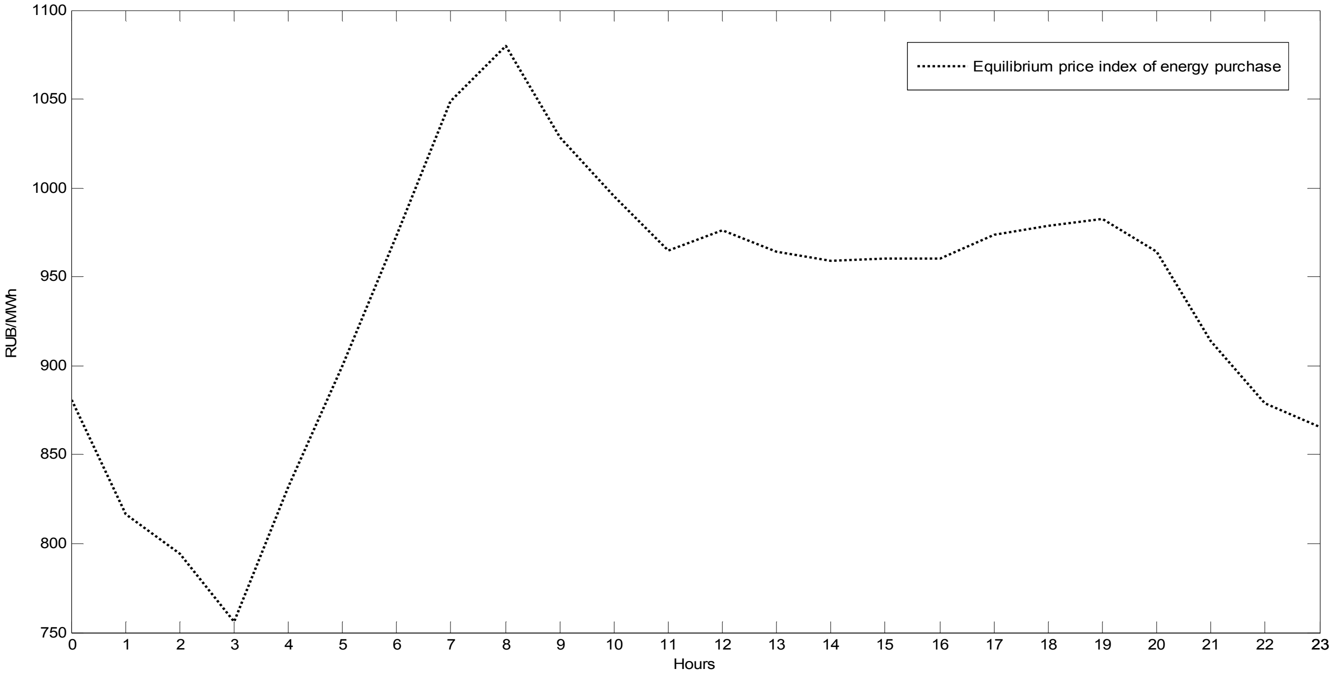

Figure 4 Example of average day-ahead prices for energy purchase in UES “Ural” (Operation day 20.09.2010).

For the buyers of energy in the power market in Russia there are risks of the spot-price increase (see Figure 4) caused by expensive offers from the generators during the peak hours, unplanned repairs of energy equipment and price manipulation. Under these circumstances, the forward markets provide a way for participants to manage their risks associated with the inherent volatility of the spot-prices (Anderson 2006).

Markets differ in whether forward contracts are physical or financial. In the Russian energy market there are no forward contracts with physical delivery of electricity in use. Participants could hedge against spot-price fluctuations via the forward contracts called 'free bilateral agreements' for electricity that are purely financial instruments. The spot-market in Russia accounts for all trade of wholesale electricity and there is obligatory participation in the spot-trade even if participant has a number of allocated forwards. This system is usually called 'gross pool' as opposed to 'net pool' in which only residual demand is traded (Anderson 2006). Thereby, the payments under the contact are made in addition to the payment for the energy sold/purchased in the spot market. Each contract includes the volume of energy V and a price s defined by the parties. At the moment of contract's execution the parties transfer a difference between the spot-price p and the contract price s multiplied by the volume V. If the spot-market price exceeds the contract price then a buyer to a contract benefits as he obtains from a generator $(p-s)\cdot V$ and vice versa.

However, application of nodal pricing in the Russian power market implies establishment of different spot-prices at every participant's location and makes a problem to conclude bilateral agreements (forwards) for delivery of predetermined amount of energy at fixed price. The point is that, if a forward contract is concluded directly between two parties it implies that they should also pay off the LMP difference between their locations in addition to the payments to a contract and spot-market. Thereby, to net out a financial contract, the market rules require counteragents to define the location where the wholesale price is set at first. This location called a delivery point (also called reference point) of the contract and it is used as a point where electricity is priced and traded (Brunekreeft 2004).

According to the market rules in Russia, a commercial operator does not register those contracts in which location of third party is used as a reference point of the contract forcing the parties to a contract to define it at one of their nodes. Thereby, in many cases it becomes difficult for the parties to negotiate which location will be used as a reference point of the contract as it hard to predict the future LMP difference. A party located at any other node than the node for which a reference price of a contract is set will be exposed to a significant risk of paying high LMP difference. Certainly, that sets counteragents in wittingly unequal conditions and doesn't allow to hedge fully. Therefore, as a rule, before entering the agreement the parties swap the price statistic at their locations in order to estimate possible values of LMP difference and mitigate the risk by readjusting the price in a contract. This principle is also used in "exchange contracts" that will be described later.

We will use a simple system (see Figure 5) to illustrate the use of the forward contracts in the Russian power market. We assume that the generator at node A and the purchaser at node B wish to hedge $100MW$ of power at price $415Rub/MWh$ during a certain hour of a trading day.

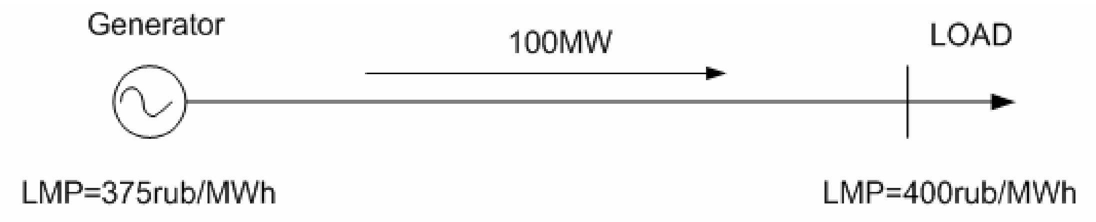

Figure 5 LMP difference between generator and consumer

At an hour, when the contract comes into force the spot-price at the generator's location is $375 Rub / MWh$ and at the buyer's location it is $400 Rub / MWh$. Participants agreed to set the reference point of the contract at purchaser's node. First, we define the revenues of the parties to a contract without taking into account their sales and purchases in the spot-market at their locations. The reference price of the contract is $p = 400 Rub / MWh$ and it is lower than the contract price $s = 415 Rub / MWh$. In this situation the generator wins as he gets from the purchaser an amount $(415 - 400) \cdot 100 = 1500 Rub$. However, the generator must sell $100 MW$ in the spot-market at his location at price $375 Rub / MWh$. His total income will be defined as a sum of profit from the spot-market and payments to a contract from the purchaser. The table below shows an effect of the contract for the generator and the purchaser.

Generator	Purchaser
Gets from the purchaser: $(415 - 400) \cdot 100 = 1500 Rub$	Transfers to the generator: $(415 - 400) \cdot 100 = -1500 Rub$
Sales in the spot market: $375 \cdot 100 = 37500 Rub$	Purchase from the spot-market: $400 \cdot 100 = -40000 Rub$
Total revenue: $37500 + 1500 = 39000 Rub$	Total cost: $-1500 - 40000 = -41500 Rub$

In this example the generator became charged with the LMP difference payments in addition to the payments obtained under the contract and from the spot-market. His total income from the contract $41500 Rub$ became reduced by an amount $(400 - 375) \cdot 100 = 2500 Rub$ that corresponds to a cost of energy delivery to the buyer's location. As opposed to generator, the purchaser only lost on the difference between the contract price and the spot-price at his location.

As a matter of fact, in this scheme possible losses or profits of the generator are unlimited. For instance, if the spot-price at the buyer's location skyrockets the generator will lose much money on covering a significant LMP difference. If the price at sink location becomes too much high the amount of payments for the LMP difference could be even greater than profits of the generator from the spot-market. To show this we will examine a situation when the spot-price at purchaser's location is equal to $1000 Rub / MWh$. The profits and losses of the counterparties obtained under the contract and from the spot-trade are depicted in the table below.

Generator	Purchaser
Transfers to the purchaser: $(415-1000)\cdot 100 = -58500 Rub$	Receives from the generator: $(415-1000)\cdot 100 = 58500 Rub$
Sales in the spot market: $375\cdot 100 = 37500 Rub$	Purchase from the spot-market: $1000\cdot 100 = -100000 Rub$
Total revenue: $37500-58500 = -21000 Rub$	Total cost: $-100000+58500 = -41500 Rub$

We can see that for the generator the contract turned out to be a defeat while the purchaser's profits are still perfectly hedged. But let's take a look to a situation from another point of view then the spot-market price at generator's location is much higher than the spot-price at the purchaser's location. We assume it to be also $1000 Rub/MWh$. In that case, the generator yields $1500 Rub$ from the purchaser under the contract and in addition he generates $100000 Rub$ from the spot-trade. His total revenues are considerable.

Generator	Purchaser
Receives from the purchaser: $(415-400)\cdot 100 = 1500 Rub$	Transfers to the generator: $(415-400)\cdot 100 = -1500 Rub$
Sale in the spot market: $1000\cdot 100 = 100000 Rub$	Purchase from the spot-market: $400\cdot 100 = -40000 Rub$
Total revenue: $100000+1500 = 101500 Rub$	Total cost: $-40000-1500 = -41500 Rub$

These examples demonstrate how much the profit of the parties to a contract would depend on the LMP difference between their locations. Generally, a party to a contract which location was not entitled as a reference point of the contract is always exposed to a risk as it becomes tightened with negative or positive payments for the LMP difference.

An alternative look to the mechanism of forward contracts realization within the bounds of nodal price formation in power markets allows considering payments for the LMP difference as the value of premium one party to a contract has to pay for its willingness to keep that contract. Indeed, by paying off the LMP difference the party under a contract equalizes spot-prices at both source and sinks locations and thereby, makes feasible settlement of the forward in a way like it is usually done in the markets with zonal price formation.

In many markets with the nodal price system the contracts called Financial Transmission Rights (FTR) are used to mitigate the risk of LMP difference. For instance, in PJM markets the participants who entering into long-term supply agreement could hedge against undesirable price fluctuations in the nodal price system through a purchase of FTRs. An owner of the FTR receives the congestion rent (LMP difference on the path between source and sink locations) from the SO. The profits obtained through the FTR accurately compensate his losses incurred by the payments for the LMP difference under the long-term agreement. However, at present the HV transmission network in Russia is the national patrimony and its transmission capacity has not been allocated between any kinds of physical or financial transmission rights. This tool remains unavailable for the participants in the transition model of the market. Nevertheless, it is in plans of the reform to create the markets of FTRs in the future.

Instead, a partial solution for the problem of unequal terms for the counteragents under a forward agreement was found in introduction of "exchange forwards". These are contracts that settled out in relation to a hub. Hubs represent groups of nodes in the power system the spot-prices at which correlate with each other. The hub price or index is defined by a commercial operator as an arithmetical mean of the spot-prices at all nodes ingressed in a hub. These indexes are on open access on the web-site of the commercial operator. The number of nodes consolidated in the hubs is different but usually each hub contains more than a hundred nodes with an observed correlation of the spot prices at these nodes and the hub price close to 95-99% (ATS 2010).

The main idea that was embodied by creation of the hubs in the Russian power market was that it would call for increase of liquidity of markets of financial contracts. A forward from location A to a hub plus a forward from a hub to location B is equivalent to a forward from A to B locations. However a contract from A to B locations is likely to only be useful if exactly these two market participants want to trade. It can be allowed for a wider range of trades by defining contracts relative to a hub.

At present, there are three hubs: "Centre"," Ural" and" South" in the first and two hubs: "Western Siberia" and "Eastern Siberia" in the second price areas of the market (see Figures 6 and 7). The parties to an exchange forward contract could define for trade any hub only if they are located in the same price area of the market with this hub. For instance, in the first price area a generator located in the hub "Centre" and a purchaser from the hub "South" could conclude and settle out an exchange forward contract in respect to the hub "Ural".

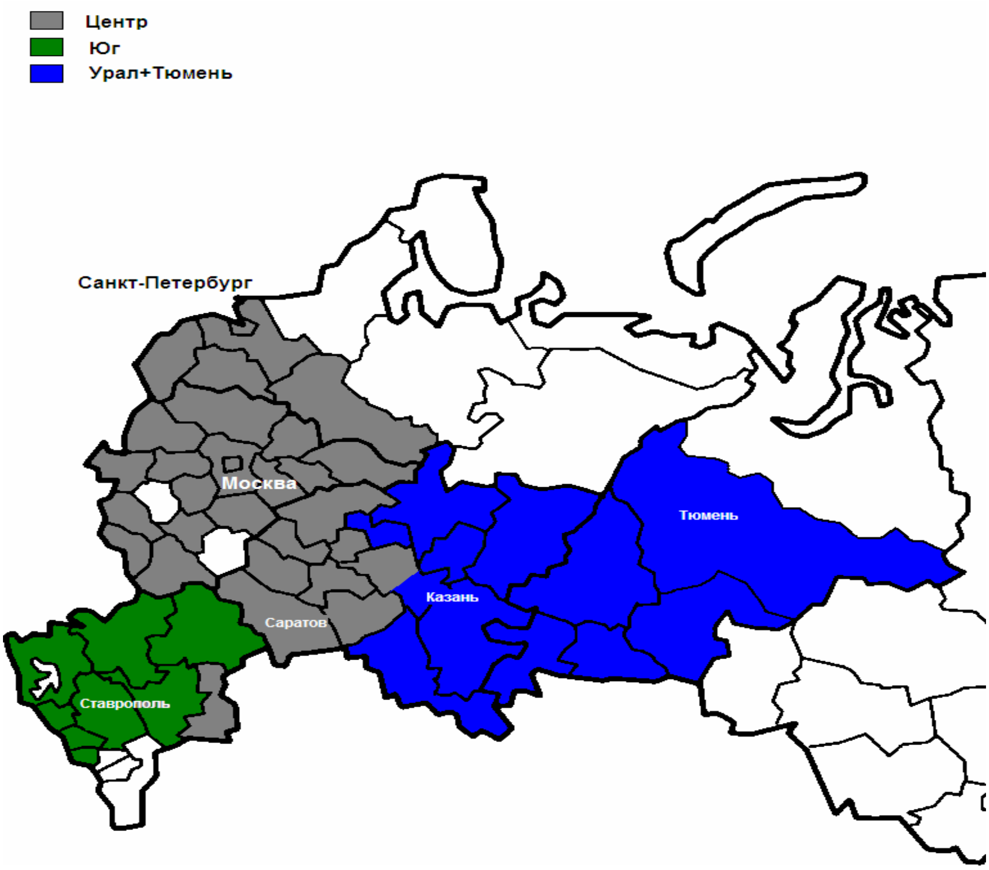

Figure 6. Hubs in the first price area of the wholesale market of Russia (ATS 2011)

Figure 7. Hubs in the second price area of the wholesale market of Russia (ATS 2011)

All exchange contracts are concluded at the power exchange “Moscow Energy Exchange” which is a commonplace with numerous contracts in circulation. Contracts contain the standard conditions of energy delivery. Minimal volume of the contract is 1 MW. Differentiation of contracts is done in accordance with delivery periods, days per weeks and hours per days. The Exchange trades contracts with contract time period from a week to a few months, or longer. There is also implied a partial execution of contracts. Participants submit to the Exchange their offers in regards to standard contracts in which they indicate the volumes of energy and price for it. Contracts are concluded at a price indicated in offers of counteragents or at a best price. Every participant also specifies a hub which he wants to be used as a reference point of the forthcoming forward agreement. This allows for more easily searching of counteragents. When the Exchange defines the counterparties with identical offers it forms an exchange contract and submits it for registration to a commercial operator.

It is implied that in an exchange forward contract a reference point of an agreement is always placed in a hub. Thereby, net profits or losses from entering into an agreement for the counteragents would depend on the price difference between a contract and a hub only. Below, in the example 1, we demonstrate this effect of a contract without taking into account the sales and purchases of the parties to an agreement in the spot-market at their locations.

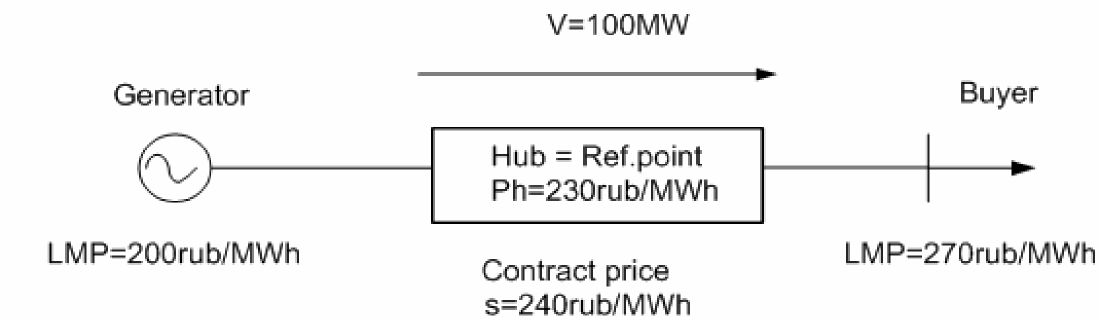

Figure 8 Usage of hub as a reference point under exchange forward contract

We assume that the parties to a contract agreed for the contract price $240 rub / MWh$. They also agreed for a hub they will use as a reference point of the contract. Let there be the price at the hub P_h equal to $230 rub / MWh$ at the moment of the contract’s realization. The generator will sale and the buyer will purchase the contract volume V at the hub price P_h and then they should transfer the positive or negative difference between the contract price s and the hub price P_h to each other. The incomes of the parties obtained under the forward agreement are shown below:

Generator	Purchaser
Gets from the purchaser: $(240 - 230) \cdot 100 = 1000 Rub$	Transfers to the generator: $(240 - 230) \cdot 100 = -1000 Rub$

Calculation of total profits or losses of the parties requires taking into account their obligatory participation in the spot-market:

Generator	Purchaser
Sales in the spot market: $200 \cdot 100 = 20000 Rub$	Purchase from the spot-market: $270 \cdot 100 = -27000 Rub$
Total revenue: $20000 + 1000 = 21000 Rub$	Total cost: $-1000 - 27000 = -28000 Rub$

In this example, conclusion of the contract turned out to be beneficially for the generator. Holding of the exchange forward contract allows him to increase his revenues from the spot-market by $1000 Rub$ while the buyer has suffered additional losses of the same amount. However, for the buyer to a contract the losses obtained as a result of energy purchase from the spot-market would be mitigated by the profits under the forward agreement if the hub price became higher than the price in the contract. Generally speaking, an effect of a contract would depend on how well the parties to an agreement are able to predict the changes of a hub price. .

As it was just shown, exchange forwards do not fully protect the parties to an agreement from spot-price changes at their locations. Instead, they just provide obtaining of additional revenue or losses to the counteragents to their incomes and expenditures in the spot-trade. However, at some certain conditions an entering into an exchange forward agreement allows participants to reach fixation of the spot-prices at their locations during the contract's execution. We will perform these conditions in our next example. For this, we must assume a perfect correlation of the prices at source and sink location with the hub price. For instance, we believe that the spot-price at the generator's location is always by $20 Rub / MWh$ higher and the spot-price at the buyer's location is always by $30 Rub / MWh$ lower than the hub price. We assume the hub price P_h equal to $550 rub / MWh$ (see Figure 9). The spot-price at generator's location then will be $P_G = 570 rub / MWh$ and the spot price at buyer's location will be $P_B = 520 rub / MWh$. The generator and the buyer want to trade 100 MW via a contract and agree for the contract price $s = 550 rub / MWh$ which is equal to the hub price. It will be shown later that the last term is very important and inalienable part of the spot-prices fixation at the counterparties' locations.

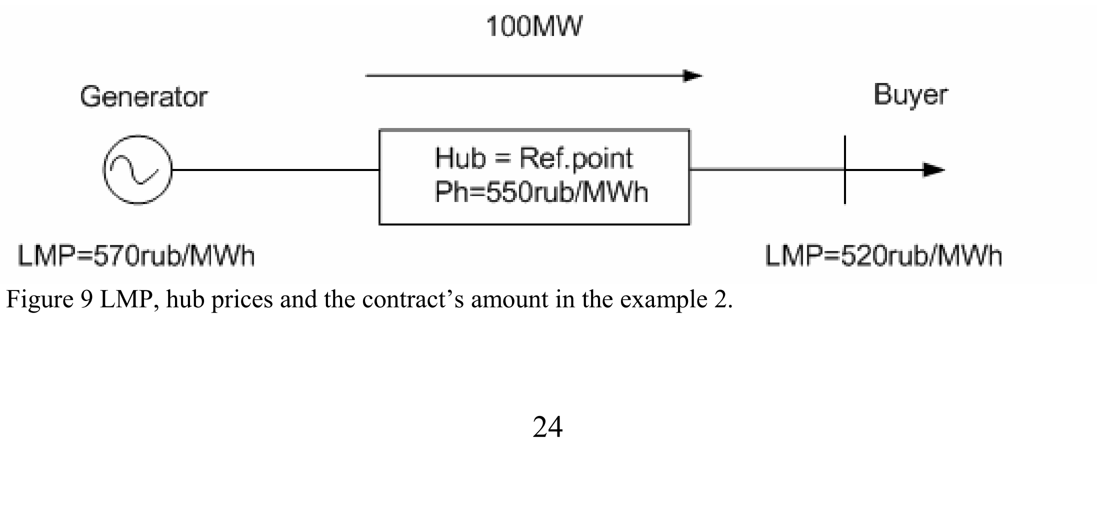

Figure 9 LMP, hub prices and the contract's amount in the example 2.

During registration of the contract in trade schedule, the commercial operator does not recognize the difference between OTC and exchange contracts. The rule to define a reference point to a contract at the source or sink location is acting for all types of forwards. Thereby, the Exchange automatically sets a reference point of the contract p at a buyer's location and re-arranges the contract's price s before its registration in trade schedule:

$$P_{contract} = s + (p - P_h) = 550 + (520 - 550) = 520 rub / MWh$$

This allows for settlement of the exchange forward in relation to a reference point established at the sink location implying that the real reference point is placed in a hub and the price under the contract is still equal to $s = 550 rub / MWh$:

Generator	Purchaser
Receives from the buyer: $(520 - 520) \cdot 100 = 0 Rub$	Transfers to the generator: $(520 - 520) \cdot 100 = 0 Rub$
Sales in the spot-market: $570 \cdot 100 = 57000 Rub$	Purchase in the spot-market: $520 \cdot 100 = -52000 Rub$
Total income $57000 Rub$	Total income $-52000 Rub$

This construction implies no profits or losses obtained under a contract. But let's take a look at the situation when the spot- prices at participants' locations will skyrocket or fall down at the hours of the contract's execution (see Figure 10). For instance, we assume that the overall level of the market prices has changed and the price at the hub $550 Rub / MWh$ became increased by $170 Rub / MWh$ .On the assumption of a perfect correlation with the hub price the spot-prices at the counterparties' locations will increase by the same value $170 Rub / MWh$. The new spot-prices at the generator's and buyer's locations will be $740 Rub / MW$ and $690 Rub / MW$ correspondingly. The new price at the hub will be $P_h = 720 Rub / MWh$.

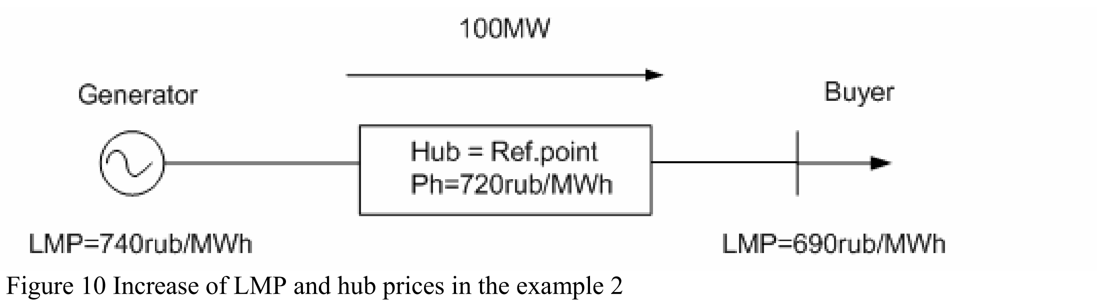

Figure 10 Increase of LMP and hub prices in the example 2

The price under the contract again will be corrected by the Exchange in order to transfer the reference point to a contract from the sink location to the hub:

$$P_{contract} = s + (p - P_h) = 550 + (690 - 720) = 520 rub / MWh$$

Financial results of the parties to the contract are depicted in the table below:

Generator	Purchaser
Transfers to the buyer: $(690-520)\cdot 100 = -17000 Rub$	Receives from the generator: $(690-520)\cdot 100 = 17000 Rub$
Sales in the spot-market: $740\cdot 100 = 74000 Rub$	Purchase in the spot-market: $690\cdot 100 = -69000 Rub$
Total income: $74000-17000 = 57000 Rub$	Total income: $-69000+17000 = -52000 Rub$

In this example, the generator is selling in the spot market at higher price $740 Rub/MW$ and gets additional profit at amount $(740-570)\cdot 100 = 17000 Rub$. But he also losses $17000 Rub$ under the forward contract and his total income becomes $57000 Rub$ which corresponds to his revenues before the market prices increase. However, it is important to note here that the scheme described above works only in case of very high correlation between the LMP at participant's locations and a hub price. For instance, if the hub price in the previous example became $5 Rub/MWh$ higher the generator would lose additional $500 Rub$ under the forward contract. Thereby, an effectiveness of hedging depends on how well the spot-prices at parties' locations correlate with a hub price.

In fact, it is possible for a participant to fix any price at his location. Indeed, if a seller and a purchaser under an exchange contract use hub as a reference point of the contract it will allow dividing the payments for the LMP difference between their locations. In simple words, a generator will always be paying off the delivery of energy from his location to a hub and a buyer will be paying for an opportunity to withdraw this energy from a hub. These monetary flows might turn to be positive or negative for counteragents depending on the hub price. If the market participant observes price correlation between his location and a hub at the proceeding of long period of time then he knows in advance how much he will pay for (or get from) the energy delivery. Thereby, he becomes capable to take the known value of the LMP difference into account when submitting his price offers to the Exchange. For instance, if the price at the generator's location is always $20 rub/MW$ exceeds the hub price than, in order to fix the price for his energy at a level not less than $400 rub/MW$, the generator should submit for the contract at price of $380 rub/MW$. The contract is concluded if there is a buyer on the other side submitting for a contract at the same price.

However, according to the number of executed exchange forwards the prices in offers of potential counteragents meet each other not often. For instance, during 2009 there were only 23 standard contracts concluded at the exchange with the total volume of energy realized under these contracts 924196 MWh (Exchange 2010a). The total volume of electricity sale/purchase through both non exchange and exchange forward contracts in 2009 constituted 85 TWh and took up around 7.6% of the total electricity market turnover (ARENA 2009).

A relatively small share of bilateral trade via forward contracts in the transition model of the Russian power market proceeds from application of regulated contracts *which are also agreements with fixed price for energy. In 2009 the sector of regulated trade took around 50% of the market and most likely that participants didn't sense an abrupt need to hedge significant volumes of their production and purchases via bilateral agreements.*

The growth of volumes traded in OTC forward contracts is also hold back by non-transparency of price formation in the location of potential counterparty and lack of mechanisms of communications between the market participants which impedes effective searching of counteragents. Most of OTC forward contracts are concluded between the parties that have long history of trust relationships. We suppose that among other reasons of the forwards' non-popularity there are risks of non-payments under an OTC contract and some acts issued by the regulators preventing participation of speculators in this market.

Besides, it is also worth to say here, that in accordance with the Tax code of Russia the tax authorities may verify correctness of a transaction if the price in it deflects by more than 20% from market prices. Thereby, for the parties under an OTC forward agreement there is a risk related to an opportunity of additional taxation if the spot-prices are significantly lower or higher than the price in their agreement.

As opposed to it, the prices in exchange contracts are always recognized by tax authorities as market prices. An interest of market players to these contracts is increasing. However, the risks of low price correlation between participant's locations and hubs (also called "basis risks") causes inability of the parties to hedge fully via these agreements and still prevents market participants from their conclusion.

5.2 Futures contracts

Electricity futures, like forward contracts are also agreements which bound the seller to a contract to supply and the buyer to accept energy in the future at price agreed today. Futures contracts have the same payoff structure as energy forwards but as opposed to them are highly standardized in contract specifications, trading locations, transaction requirements and settlement procedures (Deng 2005). The energy futures contracts are exchange-traded and defined on underlying asset which is usually the spot-market price. Each contract contains standard quantity of energy that should be delivered in the specified date of the contract's performance. Settlement of the contract involves both a daily mark-to-market settlement and final spot reference settlement, after the contract reaches its due date (Nordpool 2007). The mark-to-market settlement could be considered as a process in which traders are constantly specifying the price for the contract as the due date of the contract is coming closer. In the final settlement, a holder of the contract benefits of loses on the difference between the final closing price of the contract and the average spot-market price in the delivery period.

The market of energy futures was introduced in Russia in June 2010 by the "Moscow Energy Exchange" in consort with the stock-exchange "RTS" which also became a clearinghouse. At present, the futures trade is organized in the first price area of the market only. The reference price of the contracts defines as the spot-prices (indexes) of the hubs "Central" and "Ural". The decision about the futures contract trade in the second price area of the market was accepted on the 1st of October 2010 but the reference prices of the contracts have not been defined yet (Exchange 2010c).

All futures circulating at the “Moscow Energy Exchange” are purely financial instruments. Cash settlement is done during the trading period and the delivery date of the contract. The contracts are monthly base and peak load contracts with the time slot of the contracts’ trade is two and a half months. It is implied that the contract’s trade doesn’t stop when the delivery period starts. All contracts are traded until the last day of the delivery period and in the due date of the contract the final settlement takes place. Each contract specifies the standard energy delivery rate 100 kW per hour and the due date. The total quantity of energy delivered under a contract defines as the delivery rate 100 kW per hour multiplied by a number of hours in the delivery month. For instance, for the base load contracts with due date on 1st of October the delivery month is September and the total quantity of delivered energy will be defined as $100kWh \cdot (30 \cdot 24)h = 72MW$.

The contracts are traded daily between 10.00 and 23.50 at Moscow time at the Exchange where the contracts are concluded in a result of the continuous auction of participant’s price offers. Two times during the trading day at 14.00 and 18.45 the Exchange organizes clearing procedure as a result of which the settlement prices of futures are defined.

Determination of the settlement price of the contracts has it own peculiarities. For instance, in case of former transactions under a contract, the settlement price will be accepted equal to the price of last transaction. The price of last transaction is also used when there are no any price offers for the contract during the prior trade session. However, if during the prior trade session a certain seller/buyer has submitted the price offer lower/higher than the price of last transaction under the contract then the settlement price of the contract will be the price of his offer. In case if there were no previous transactions under the contract, the settlement price defines as an arithmetic mean of the best sale and the best purchase price offers submitted during the previous trade session.

In the following example, we show an effect from entering the futures contract. We assume that an Exchange member wants to fix the purchase price for 5 MW of energy during every hour of September 2010 in relation to the hub “Ural”. The total amount of power purchased in September will be $5 \cdot 24 \cdot 30 = 3600MW$ .On the 1st of August 2010 he buys 50 futures contracts at price $927 rub / MWh$ with the due date 1st of October 2010. The total cost of concluded contracts is $927 \cdot 3600 = 3337200$ Rub .

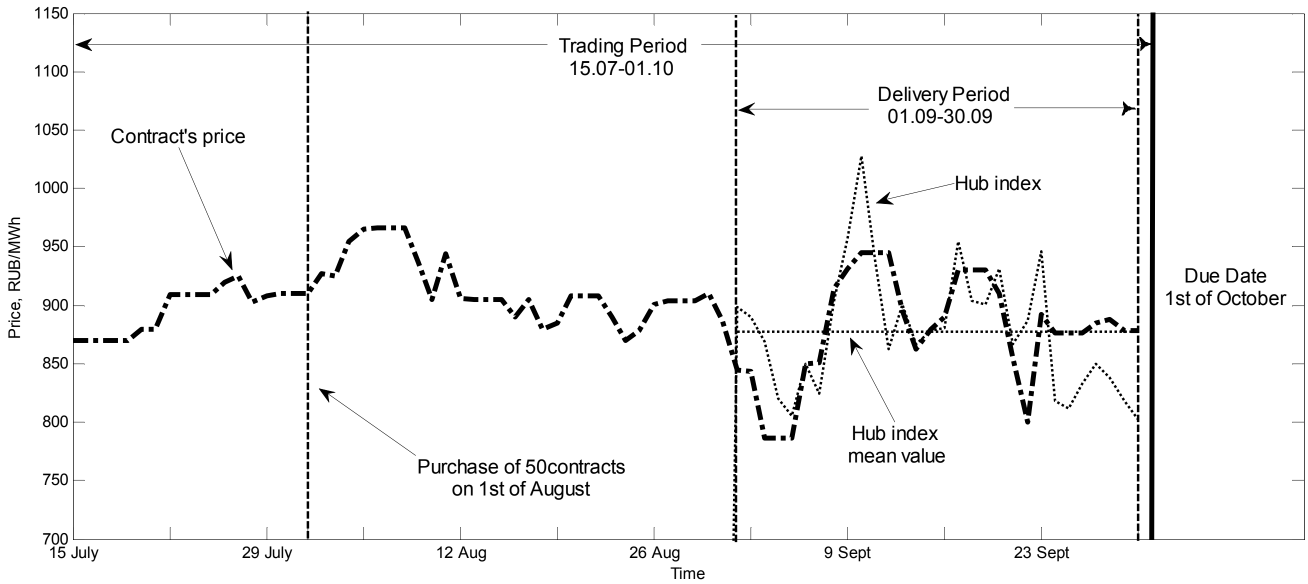

Figure 11 Time slot of the futures contract trade (contract EUBM-9.10) and the spot-price index of the "Ural" hub

The illustration above shows the changes of the futures price during August-September 2010. Mark-to-market settlement during the trading period covers gains or losses from day-to-day changes of the contract's price. In our example, from the date the contract was purchased to the contract's due date the price for the contract decreased to $878 rub/MWh$. Thereby, the member will be debited $(927-878)\cdot 72\cdot 50 = 176400 Rub$ during the trading period. The final settlement under the contract on the 1st of October implies that the member is debited or credited an amount equal to the difference between the average hub index in September and the final closing price of the futures contract defined on 30th of September. However, in our example, the average hub index $878 rub/MWh$ and the final price for the contracts have converged (which, in general is typical for the futures contracts but not always be the case). Thereby, throughout the final settlement the member will be charged an amount of zero and his total losses under the contract will remain $176400 Rub$. As we could see it, without the futures contract the exchange member would expend in the spot-trade during September an amount $878\cdot 3600 = 3160800 rub$. Holding of the contract increases his expenses incurred in the spot-market to $3160800+176400 = 3337200 rub$ which corresponds to the purchase of $3600 MW$ in September at price $927 rub/MWh$.

Entering the futures contract requires from the traders posting of performance bond which makes up 4-15% of the contract's settlement price. For the contracts traded at the Exchange, the amount of payments for performance bond is defined on a daily basis as the difference between up and lower limits of the contract's settlement price multiplied by the cost of the contract's price change by one point. For instance, in our example, one contract requires an amount $(961-795)\cdot 72/1 = 11952 Rub$ of the performance bond. When the contract reaches its due date the performance bond payments are returned to the counterparties.

Generally speaking, an effect obtained from the futures contract and from the exchange forwards is the same. Both contracts allow market participants hedging against energy price changes during the delivery period of a contract. However, the risk of a counterparty default under the futures contract is minimal as all transactions under the contracts are made via the Exchange. The fact that the gains and losses of electricity futures are paid out daily, as opposed to being cumulated and paid out in a lump sum at maturity time, as in trading forwards, also reduces the credit risks in futures trading (Deng 2005). As compared to forward contracts, the futures contracts owing to their standardization and price transparency are more liquid instruments of trade. The table 5 shows the monetary turnover of the futures contracts market from June to September 2010.

Table 5 Number of transactions to the futures contracts and volumes of transactions (Exchange 2010b)

Month	Transactions to the contracts	Volumes of trade, Rub*
June	299	10 671 090.04
July	2 930	75 423 095.8
August	12 853	514 640 928.6
September	13 437	258 990 147.7

**Currency exchange rate: 1 EUR =40RUB*

At present, there are 11 brokers companies operating in this market sector and one energy company "IES-Holding". Mainly speculative transactions take place. The number of fulfilled futures contracts in July and August 2010 is equal to 216 and 716 correspondingly (Exchange 2010b).

In summary, the futures contracts are more attractive mechanism of hedging for the market players that exchange forwards. Thought, the futures contracts also don't eliminate the risk of LMP difference, they allow for application of the wide range of strategies of the market players. For instance, one such strategy is called "cross" hedging when the contract for energy could be secured by the futures contract for gas. Among the other benefits of the futures contracts is an opportunity to conclude speculative transactions which are forbidden in forwards. That also increases interest of the players to this market as at the relatively low transactions and monitoring costs the potential revenues obtained as a result of speculative operations under the contract (sale of the futures contract at high price and further purchase of the same contract at lower price) could be high enough.

6 Capacity market

Capacity is a commodity the purchase of which gives to a consumer right to claim readiness of generating equipment to produce energy. Failing to maintain his equipment in a proper manner due to scarcity monetary resources a generator deteriorates whole system reliability and puts consumers at risk of not being supplied with sufficient amounts of energy at peak hours of load. Thereby, capacity payments can be considered as what consumers should pay for maintaining of the system reliability and keeping of sufficient amounts of reserves in the power system. Owing to separate flows of payments for capacity, producers then have less incentives to submit high price offers to the energy market as opposed to the market of electricity only, where, for instance, an owner of peak generation has to charge the energy price in his offer in attempt to cover the full costs of production during the few hours of operation in the market. In the market where separate trade of energy and capacity is organized this doesn't happen because payments for capacity cover significant share of the fixed costs of generation. As a result, the overall effect of the separate capacity payments introduction reveals in smoothing of the spot-market prices fluctuations and reduction of the prices for energy (Market Council 2010d).

Besides guarantying of sufficient supply resources in the power system to meet expected peak demand plus an installed reserve margin, the market of capacity ensures that capacity resources are appropriately allocated in the power system (PJM 2009).The point is that the market in regions with insufficient amount of capacity resources inside would send the adequate signals for investments in a form of increased capacity payments.

6.1 Transient period of the market 2008- 2011

In Russia, before the power market opening in 2006 there had been inseparable payments for capacity and energy. Between 2006 and 2008 capacities of stations were paid off separately at the tariffs established every year by the Federal Tariff Service (FTS) of Russia. In July 2008 the capacity market of transient period was introduced in which a certain percent of capacity volumes allowed for participation in deregulated trade was rising from year to year. To complete the energy and capacity markets reforms simultaneously, the rates of the capacity market liberalization were decided to be synchronized with the rates of the energy market liberalization. Thereby, the transient model will be until 2011 after which the regulated trade will be stopped and the long-term capacity market model will be introduced.

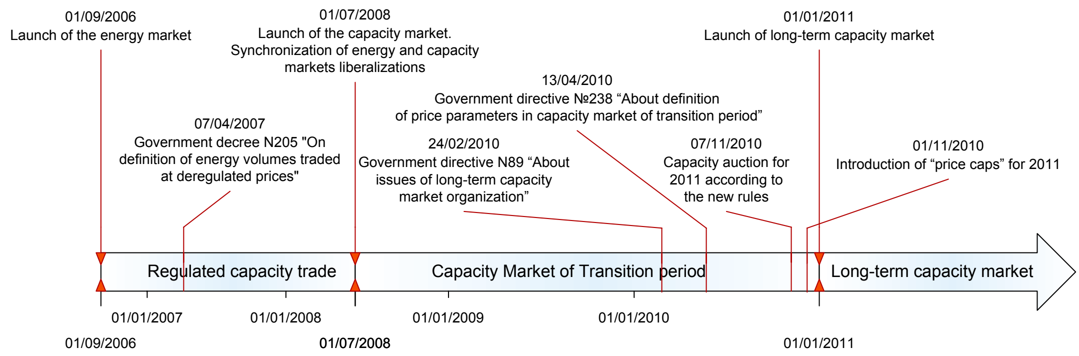

Figure 12. Milestones in capacity market development in Russia

6.1.1 *Regulated trade*

At present, around 10-20% of capacities are still purchased /sold under the regulated contracts but this refers only to the power plants (including hydro and nuclear stations) that had been constructed before 2007 year. Capacity prices under regulated agreements are established every year by the Federal Tariff Service of Russia and reflect owners' annual expenses on maintenance of power stations. Specifically, the tariffs are defined taking into account forecasted rates of inflation, expected changes of fuel prices, technological peculiarities of generating objects and changes of tax rates.

New hydro and nuclear stations put into operation after 2007 can choose between participation in the deregulated trade and conclusion of long-term capacity supply agreements with the government which, in general, are similar to regulated contracts. For instance, there is also a so called "linkage" under these agreements is used when the consumers in areas of free power flow are linked to a specific station selling capacity at regulated price. The payments under an agreement are collected from all consumers in the areas where the station is constructed. The prices under long-term capacity agreements with new hydro and nuclear stations also defines the Federal Tariff Service which sets them in such manner to ensure gradual reimbursement of the investments put in construction of the stations over 25 years.

New heat stations are also eligible to enter into long-term contracts with the state called "Capacity Delivery agreements" which are similar to the agreements with the new nuclear and hydro stations. However, the final design of these contracts has been adopted only at the end of 2010 just before the launch of the long-term capacity market model and during the transient period of the market some other mechanisms of new capacities' costs compensation were used. Conclusion of these contracts was postponed mainly because of the disagreement of private generation companies with their terms.

6.1.2 *Deregulated trade*

As opposed to old generation, new power plants including new hydro and nuclear stations put into operation after 2007 have been released from participation in regulated trade right from the start of the reform. Capacities of these stations during the transition period of the market are allowed to be sold at relatively high prices in order to compensate their construction costs over the period of 10-15 years. Both the liberalized capacities of old generation and capacities of new generators are traded in deregulated sector of the market in which several opportunities how to get payments for capacity exist:

First. Capacity could be traded bilaterally, i.e. the market participants are allowed to conclude capacity forwards contracts which ensure capacity supplies during the agreed period of time at fixed price freely set by the counterparties. The contracts could be concluded both before and after annual capacity auctions and allow the market participants to hedge against undesirable capacity price changes. The market of bilateral capacity forwards will be considered in more details in the chapter 7.

Second. All stations except the new hydro and nuclear power stations concluded long-term agreements participate in competitive capacity auctions organized by the SO for each of 28 areas of free power flow in Russia. During the transient period of capacity market 2008-2011, competitive auctions are held annually to select necessary volume of capacity for a following year. The generators participating in auctions get payments for their capacity at the prices indicated in their capacity bids (pay-as-a bid principle) multiplied by a seasonal ratio. In turn, consumers purchase capacity at a single price in every area of free power flow which defines as the average price in the selected offers of generators. Before auctions the SO forecasts capacity demand taking into consideration the value of necessary reserve in each area of free power flow. The volumes that should be selected in an auction are then defined as a difference between annual aggregate capacity demand volume and capacity resources under regulated and long-term capacity agreements with new nuclear and hydro stations. The volumes in forward contracts for capacity are excluded from the supply curve at the beginning but become taken into account during the actual capacity price estimation at the end of a year. This last peculiarity has significant impact on the price of an auction always leading to increase of capacity payments for consumers at the end of a year. Although, there are no direct "price caps" in the market, some limitations for the offers of generators in the transition model exist. For instance, old generation is not allowed to set capacity prices in the offers higher than the tariffs in their regulated capacity agreements and the price offers of new stations are a subject of economical evaluation carried out by the market regulators.

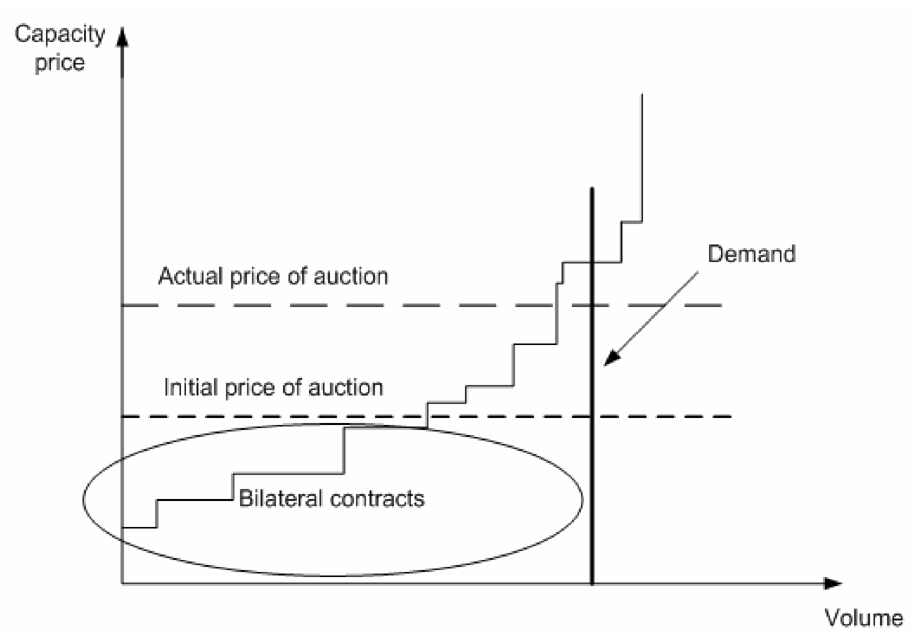

Figure 13. Model of annual capacity auctions in the transient period 2008-2011

In 2011 the long-term model of capacity market will be introduced and annual auctions will be replaced with long-term auctions in which capacity will be selected 4 years ahead before its actual delivery. The last auction in the transient market model had been organized before the 1st of October 2010 in which the capacities for the year 2011 were selected. Before the 1st of June 2011 the auction to select the capacities for the period 2012-2015 will be organized. In case of insufficient volume of capacity selected in auctions or stations' startup delay, adjusting auctions might be organized by the SO. Those capacities that are not selected in auctions but are still needed under the system's reliability terms will be referred to the stations operating in "forced" modes and rewarded at the tariffs stated by the FTS of Russia.

6.2 Capacity market after 2011

6.2.1 *"Price caps" in capacity auctions*

In the new market model old generation is no longer bound with regulated tariffs and could submit any price offers to capacity auctions on a par with new stations. However, this is possible only in the areas of free power flow with sufficient level of competition. In auctions organized in the areas where competition is poor old and new generation is forbidden to submit price offers beyond "price caps" stated by regulators. The market rules do not establish permanent "price caps" for a long space of time. Instead, it is planned that their values will be re-estimated annually depending on changes of competitive situation in the areas of free power flow.

The values of "price caps" for 2011year were determined by the government in the directive № 238 from 13th of April 2010 "On definition of price parameters of capacity trade". In the areas of free power flow located in the 1st price area of the wholesale market the “price cap” value for the 2011 year is 118125 RUB/MW per month. In the 2nd price area of the wholesale market the “price cap” is captured at the level 126368 RUB/MW per month. For those areas of free power flow where the price cap is applied the minimal capacity price is defined as a product of step-up coefficient 1.05 and the minimum of regulated tariffs stated for the generators in corresponding price area in 2010 year. The “price caps” for the following years have not been announced yet.

Interestingly enough, in September 2010, after analyze of the capacity market quality carried out by the Federal Antimonopoly Service the “price caps” for 2011 were applied in 26 of 29 areas of free power flow containing in total approximately 60% of all capacities of the market. It was stated, that scanty level of competition in these areas does not allow for conducting of full-fledged capacity auctions there. In the rest of areas where “price caps” were not applied the Federal Antimonopoly Service established additional requirements of “price reasonability” to offers of generators. Later, the special degree of the government issued in November 2010 introduced “price caps” on the whole territory of the second price area of the market including the only area of free power flow in Siberia where “price caps” previously had not been stated by the Federal Antimonopoly Service.

6.2.2 *Capacity auctions in areas of robust competition*

In the areas of free power flow where “price caps” are not applied the price of capacity in auctions defines with some limitations. Thus, in according to auction rules to restrict monopoly positions of some large suppliers or a group of affiliated suppliers that own more than 15% of total capacity in any area of free power flow located in the 1st price area of the market (10% for any areas of free power flow in the 2nd price area) an obligation to submit only price accepting offers in respect to all of their capacity volumes exceeding these 15% (10% in areas of free power flow in the 2nd price area) is introduced. After these constraints are met, the capacity price in an area of free power flow defines as the minimal magnitude of the following values:

1 Maximal price offer among the offers with lowest prices submitted to an auction and containing in aggregate 85% (90%) of total capacity volume selected in this auction if it is organized in 1st (2nd) price area of the wholesale market. Thereby, 15% and 10% of most expensive generation in the first and second price areas correspondingly do not participate in the marginal price formation in auctions.

2 Equilibrium capacity price that would be determined in an area of free power flow if the capacities were selected in accordance with the criteria of capacity cost minimization and technical requirements of the energy system functioning were not taken into account.

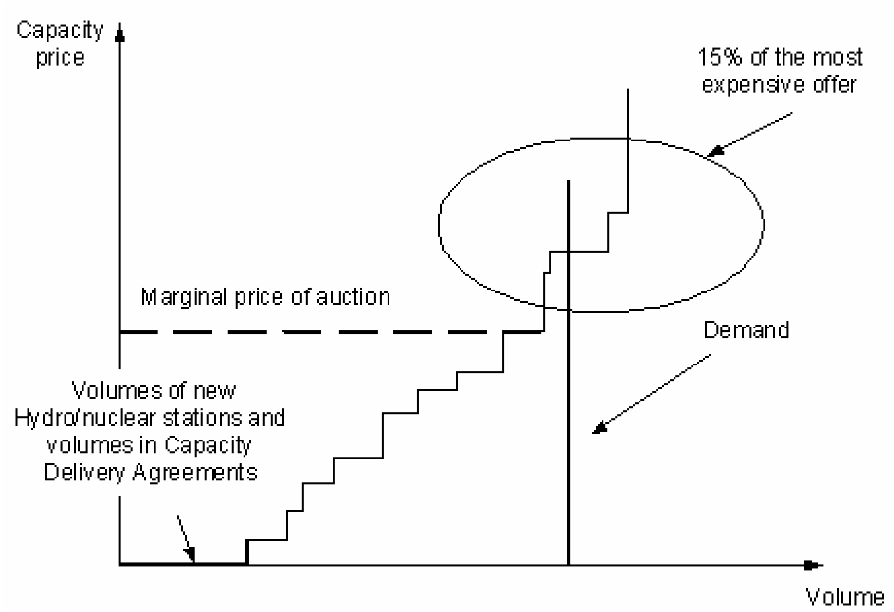

Figure 14 Capacity auction scheme in the long-term market model

The generators with the price offers below the marginal price of auction will be getting capacity payments at the marginal price. In turn, those capacities that were selected during auctions but have the prices in their capacity offers beyond the marginal price of auction will be paid off in accordance with their offers ("pay as a bid" principle). However, the offers with the highest prices will be testing by the FTS for the purposes of their economical reasonability. If the price offer significantly exceeds the true costs of a generator then a "fair" price could be established by the FTS and capacity of the generator will be paid off during the next four years at the latest price.

During auctions, capacity of new stations (including the new nuclear and hydro stations concluded agreements during the transient period) constructed under long-term agreements with the government will be taken into account as a price accepting offer. Old nuclear and hydro capacities participate in auctions on a ground basis with heat stations. However, in 2011 and 2012 the monetary funds necessary for their reliable operation as well as an investment component will be included in the cost of their capacities. Since the year 2013 some price markup is possible if during 2011 and 2012 years a nuclear or a hydro station will not get all necessary means to provide reliable and secure operation.

For 2011, only two among 29 areas of free power flow in Russia were defined as areas with unrestricted competition. The prices submitted by generation in these areas in preliminary auction for 2011 were relatively high (see Appendix 4). Following that, most of expensive generators and generators that did not meet requirements of the SO were entitled as "forced state" generation and got regulated tariffs. Capacity prices stated by the Federal Tariff Service for these stations vary in wide range but in many cases they are higher than "market" prices and "price caps". In result of this, in the actual capacity auction for 2011 conducted later in two areas with robust competition the price of capacity did not exceed the level 123000 RUB/MW per month.

7 Hedging instruments in the capacity market

7.1 Bilateral Capacity Contracts

The advent of deregulation in the capacity trade called for a tool which would allow the market participants to hedge against undesirable price changes in the capacity market. Such a tool became the bilateral contracts for capacity. These contracts represent the obligation to purchase or sell a fixed amount of capacity at a pre-specified contract price at certain time in the future. In general, they are similar to the forward contracts for energy and could have been entitled as "capacity forwards" if there were no some remarkable peculiarities of these contracts. Thus, for instance, these contracts always include some portions of electricity supplies inseparably linked with capacity delivery. In simple words, if a generator decided to sell his capacity via the contract to a purchaser he would always be bound up with selling of some quantity of energy to the same purchaser. This additional sale and purchase of energy under a contract has direct influence on the finite cost of capacity for the counterparties and makes impossible the full hedge under a contract. There has always been many argues about the reasonability of this design solution for the bilateral contracts for capacity. Indeed, in the Russian power market energy and capacity are two separate commodities traded in the separate markets with their own demand and offer and there is no objective reason to tie them with each other. Partial explanation of why this condition was brought into the contracts is just because the regulators didn't want to allow for sales of the capacity which is not ensured by generation of energy. Besides that, the second reason for presence of energy in the contracts exists. The point is that when the market of energy was opened in 2006 it was expected that the market participants would start entering the forward contracts on a mass scale. However, two years later from that the volumes of energy traded in the contracts stayed at relatively low level. When the capacity market was near the launch in the middle of 2008, the regulators decided to increase liquidity of the market of bilateral contracts for energy by prescribing of its obligatory supply in the contracts for capacity.

7.1.1 *Risks of capacity market*

Recall that in the transition model of the market the capacity price is determined in the annual competitive capacity auctions hold by the System Operator. During these auctions organized at the end of every year for each area of free power flow, the generators submit their volume and price offers for capacity. The SO places price offers of the generators in ascending order and forecasts capacity demand in each area of free power flow. The necessary volume of generation in each area then defines as a result of intersection of the step-bid supply and inelastic demand curves (recall that the purchasers of capacity don't submit their price offers to annual auctions). The single price of capacity for the consumers is the average price in the offers of generators selected in auction. In turn, generators get payments for capacity in accordance with their price offers. In this situation, a generator with low capacity price offer may increase his profits by entering a bilateral contract for capacity. The point is that a generator gets tangible benefits if he manages to conclude a contract at price higher than his price offer submitted to auction. In turn, a purchaser to a contract also benefits as he gets capacity at price lower than the average price in his area of free power flow.

The SO does not take into account the amounts in contracts when he defines the *initial* price of capacity in the auction. However, they are removed from the offer curve when the SO estimates the *actual* price. Practically, the most of the low-price capacities cope with entering the contracts and, therefore, the *actual* price in the auction becomes driven by more expensive generation.

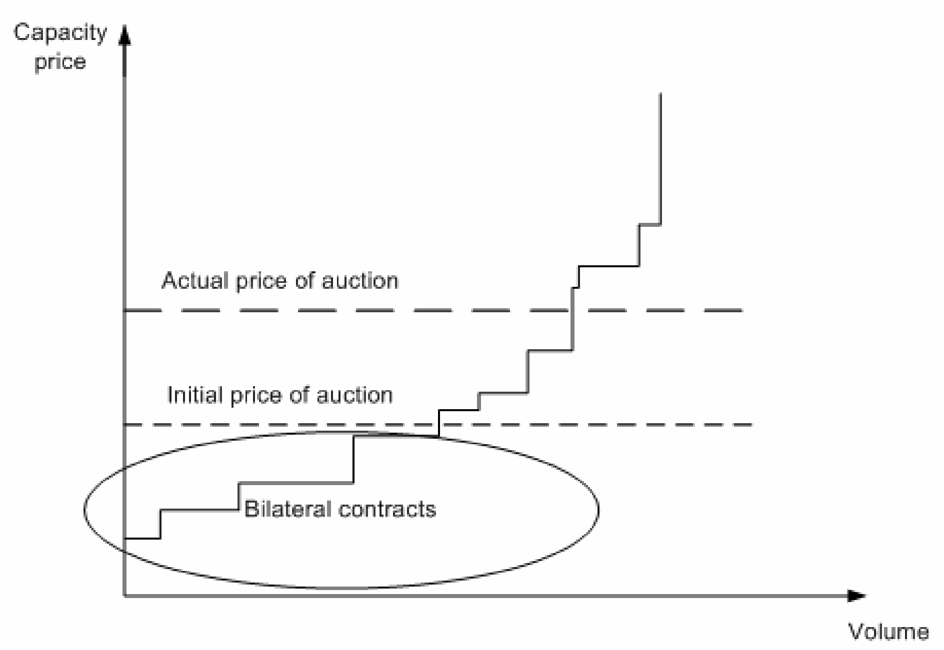

Figure 15. Impact of the bilateral contracts on the price of capacity auction

The price of capacity also changes significantly at the proceeding of the year for instance due to its resale and non-readiness of generating equipment to produce power (analogically to balancing market of energy). In this situation, conclusion of the bilateral contract mitigates the risks of the capacity price changing in the market.

7.1.2 *Over-the- counter contracts*

At present, the OTC contracts can be concluded between the market participants for capacity uncovered by regulated and other long–term capacity supply agreements. The notable distinction of the contracts is that in these contracts a generator can not state position of a purchaser to a contract and vice versa. In addition, these contracts have significant restrictions concerning the counterparties to a contract. For instance, they are allowed between the counteragents that already have a regulated contract. The volume of capacity in such contracts can not exceed the volume of capacity which would be determined for the counterparties if capacity was sold fully at regulated prices. These contracts are usually entitled as the "bilateral contracts at the expansion of regulated contracts". Also, the OTC contracts can be concluded between consumers and new generators (introduced after 2007) with respect to their capacity selected in the annual auctions and nuclear/hydro stations with respect to their capacity uncovered by any other long-term agreements.

The contracts are allowed either between the counterparties located in the same area of free power flow or between the counterparties located in different areas of free power flow. For the second case, the commercial operator defines for each generator the limits of his capacity supplies into other areas of free power flow within which the counteragents can conclude a contract. The delivery period under the contracts can vary from one month to one year or more. The minimal quantity of energy that must be supplied through a contract is 1 kWh. The maximal quantity of delivered energy can not be higher than the volume of capacity delivered under a contract in the corresponding period. Within the given limits, the volumes and prices of energy and capacity in the contracts are freely determined by the counterparties.

The contracts are settled out physically in regards to capacity delivery (placing of capacity at a consumer's disposal) and financially in regards to energy. Settlement of the contracts with respect to energy is organized similarly to a settlement of the forward contracts for energy. The contacts require the counteragents to define a location where the reference price for energy P^E will be set first (recall that the reference point can be placed only at one of the counteragents' locations). Then, the contracts are set financially i.e. the counterparties are paying off the price difference between the reference price P^E and the energy price P^e stated in a contract. Below, we consider an effect from entering the OTC bilateral contract for capacity at greater length.

Let's assume that a generator agreed with a purchaser about the delivery of *80 MW* of capacity during September at the price $100000 Rub / MW$ *per month.* Also, we assume that they agreed for the delivery schedule of electricity as shown in Figure 16 at the fixed price $800 Rub / MWh$

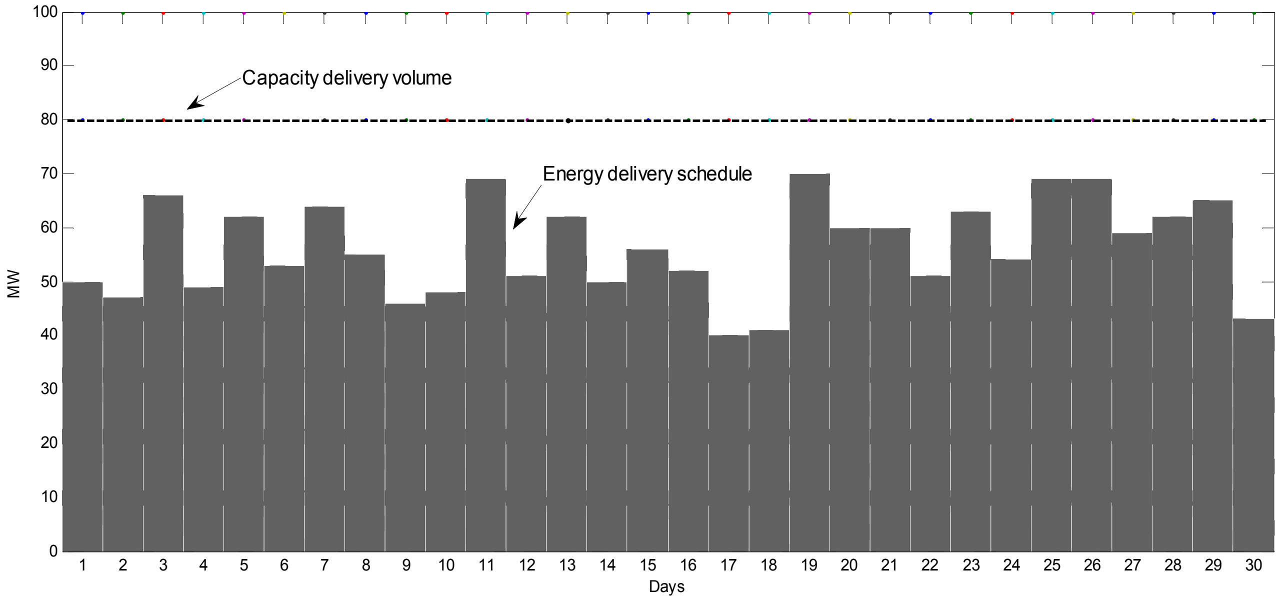

Figure 16. Energy and capacity supplies under a bilateral capacity agreement

The total gains and losses of the generator obtained as a result of energy sale to the contract can be written as $\sum_{h=1}^{T}(P_h^E - P^e)\cdot V_h^e$, where T is the total number of hours in the delivery period to a contract and V_h^e is the volume of energy delivered at hour h. To simplify our calculations, let us suppose now that the average energy price at the reference point of the contract in September is $P_{average}^E = 950 Rub/MWh$ and the total volume of energy $\sum_{h=1}^{T} V_h^e$ delivered under the contract is $1686 MW$. Sale of capacity generates an amount of $8000000 rub$ but the generator loses on sale of energy an amount $(950-800)\cdot 1686 = 252900$ rub. Thereby, his total cost of capacity sold under a contract will be $8000000 - 252900 = 7747100 Rub.$ which corresponds to the actual price of *80 MW* equal to *96838.75 Rub/MW per month*. In this example, the contract became unprofitable for the purchaser as he sold capacity at lower price. However, the picture changes if we assume the average reference price higher than the price of energy in the contract. In this case, the contract is beneficial for the generator because the purchaser to a contract will become charged with payments for energy to the generator that in turn will increase the finite cost of capacity sold under the contract.

Generally speaking, generators and big industrial consumers might be not interested in splitting a contract into capacity and energy cost components and prefer to set the joint account of a contract. However, this is totally inappropriate for the retailers which usually translate the energy and capacity prices from the wholesale market to their end-users. For them, it is important to know the cost of capacity and electricity they purchased via the contract separately. Thereby, in the contracts concluded over the counter only purchasers (retailers) can indicate the separate prices for capacity and energy to the commercial operator.

7.1.3 *Exchange contracts*

7.1.3.1 Contracts and process of trade

The contracts traded on the Exchange are standardized monthly, quarterly and half-year contracts. As opposed to the OTC contracts, they do not contain separate prices for capacity and electricity. Participants must submit to the Exchange their offers for purchase or sale of capacity and energy at a single price. The contracts are differ whether energy under a contract is supplied in peak, half-peak or base-load periods. The volume of electricity in every contract is proportional to the volume of capacity supplied via a contract. It is determined as quotient from division of 0.25 MW of capacity by the coefficient $k_{z,m}^{rez}$ calculated by the SO for each month of the year in both price areas of the market. Table 6 depicts the values of $k_{z,m}^{rez}$ in different months.

Table 6. Relation between capacity and energy volumes in Exchange contracts in different months (Market Council 2010e)

Month	1^{st} price area	2^{nd} price area
January	1.261	1.434
February	1.263	1.473
March	1.349	1.359
April	1.471	1.622
May	1.600	1.801
June	1.653	1.922
July	1.585	1.958
August	1.560	1.892
September	1.465	1.764
October	1.321	1.596
November	1.220	1.469
December	1.177	1.361

All contracts are concluded in regards to "lots" which contain the standard quantity of capacity 0.25 MW and energy $\frac{0.25}{k_{z,m}^{rez}}$ MWh. In their offers participants specify an amount of lots they wish to sell or purchase and the price of one lot. The rules of the exchange trade allow the counterparties located in different areas of free power flow to enter the contracts. However, any generator has an option to restrict in his offer the volume of sales into the other area if he finds it necessary.

The Exchange organizes four trade sessions per day during which the buyers and sellers could submit the offers. The prices in the contracts are found in result of the marginal auctions hold in the end of each trade session. During the auctions, the participants' offers in the areas of free power flow are aggregated into supply and demand curves in the same way as in the spot-market price calculation. The possible delivery or withdraw of capacity from the other areas is also taken into account as price independent offer.

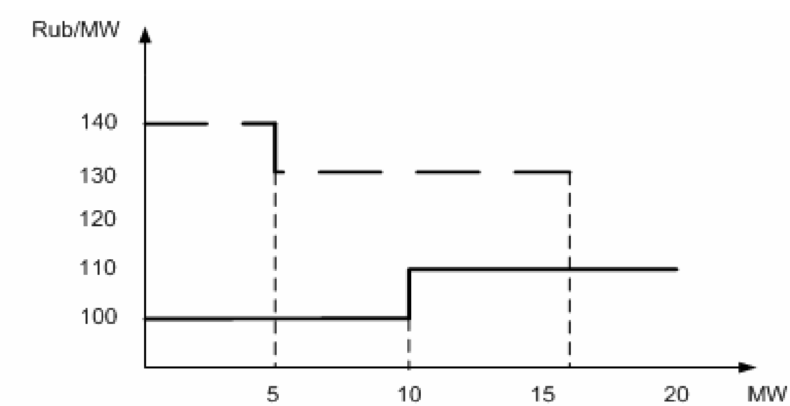

Figure 17 Example of the marginal auction

The Exchange trade continues every working day until 23rd day of each month (Exchange 2010c). After that date the Exchange forms the list of bilateral contracts for capacity and submits it to the commercial operator for registration. In turn, the commercial operator estimates the prices of energy in every area of free power flow. These prices are defined as the average values of hourly energy prices in all nodes located within the corresponding areas and later used as the reference prices in the contracts. Settlement of the exchange contracts with respect to energy organized in analogue with settlement of the OTC contracts and requires the counterparties paying off the difference between the price of energy under a contract and the reference price.

7.1.3.2 Hedging of capacity price under the contracts

As it was shown earlier, the profits or losses obtained in result of energy sale and purchase under the contracts decrease or increase the cost of capacity for the counteragents. However, they could mitigate this risk by entering an opposite energy forward contract for the same amount V^e in which the seller of capacity is a buyer to a contract and the buyer is a vendor. Let's consider an exchange contract for capacity. Without an energy forward contract a generator loses the amount $(P_Z^E - P_c^e) \cdot V^e$ when the price in the area of free power flow P_z^E is higher than the price of energy P_c^e delivered under the contract (for simplicity, we divide capacity and energy costs under a contract). If there is additional exchange forward contract concluded at the price P^e, the generator will receive back the amount $(P_{Hub}^E - P^e) \cdot V^e$, where P_{Hub}^E is the reference price of energy supplied under the contract. The generator is completely hedged if the condition $(P_Z^E - P_c^e) = (P_{Hub}^E - P^e)$ is hold. Recall that the areas of free power flow are located within the hubs which means high correlation between the prices P_Z^E and P_{Hub}^E. Thereby, the price P^e in the energy forward contract could be roughly estimated as $P_c^e - (P_Z^E - P_{Hub}^E)$. In this scheme, even if the spot-prices skyrocket or fall down it will not affect the cost of capacity delivered under a contract. The same effect can be also achieved if the futures contract for energy is applied instead of forward.

7.1.3.3 Accounting forward contracts for capacity

In 2009 the Exchange also provided an opportunity to conclude the accounting forward contracts for capacity. The contracts didn't imply real physical delivery of capacity and energy and were used for the resale of capacity during the trading sessions at the Exchange. For instance, if a buyer was purchasing the volume of capacity from a generator at certain price he could later resell this volume to another purchaser at higher price. The resale of capacity ended in the end of the month with conclusion of a physical contract between the generator which made the initial emission of capacity and the last purchaser. The Exchange required from the traders posting of performance bond and organized day-to day settlement of the contracts. However, these contracts were cancelled due to their incorrect impact on the capacity trade. The problem was that the market participants used the difference between the price at the Exchange and the *initial* price of capacity defined in the annual auctions to get additional profits. Indeed, according to the market rules all capacity purchased via the bilateral contracts which exceeds the actual consumption must be sold back at the *initial* price of the annual auctions. The generators that purchased capacity for own consumption and the consumers simply started buying at the Exchange excessive volumes of capacity at prices lower than the *initial* price and reselling it back to the SO. As the result of these operations they were getting additional revenues. First, the regulators prohibited the generators to buy more capacity than they needed to cover their own actual consumption. Then, they also applied the same restrictions to the consumers. As the result of this, in 2010 there was no accounting forwards for capacity concluded.

7.1.4 *Volumes of trade*

Since the market of the OTC bilateral contracts for capacity was opened in July 2008 the volumes of capacity traded in these contracts were constantly increasing while the volumes of energy remained relatively low. In the last six months of 2008 the total volume of capacity realized through the OTC contracts constituted 87.1 GW and the volume of energy sold and purchased through these contracts was only 0.16 TWh. For comparison, in the same time period the total sales under energy forward contracts were estimated as 42.58 TWh. (Market Council 2008). The market participants preferred to conclude energy forward contracts rather that sell and purchase energy via the bilateral contract for capacity. This situation had been dragging at least until the beginning of 2009 when the exchange bilateral contracts for capacity were introduced and the regulators enforced the market players to participate in exchange trade. They simply prohibited the generators to submit capacity bids to the annual auctions if they had not offered their capacity to the Exchange beforehand.

However, in 2009 the total volume of capacity traded in the OTC contracts increased and was captured at the level 216.75 GW which constituted 10% of the capacity market turnover. The volumes of capacity sold under exchange contracts were 121 GW and took up 5.6% of the market (ARENA 09).

Table 7. Amount of capacity realized via the exchange contracts in 2009 (Exchange 2010a)

Month	*Amount of contracts*	*Volumes in contracts, MW*
February 2009	100	2530
March 2009	279	7995
April 2009	224	6321
May 2009	247	5948
June 2009	305	9430
July 2009	378	16571
August 2009	319	11313
September 2009	460	13801
October 2009	448	13086
November 2009	426	14403
December 2009	454	16552
January 2010	475	26554

At present time, the exchange contracts for capacity are prevailing under the OTC contracts in the first price area of the market. In turn, in the second price area the bigger volumes of capacity are still sold and purchased via the OTC contracts because of many hydro stations in this area which are allowed to enter these contracts. The total volume of capacity realized in the OTC contracts in the first and second price areas of the market from January to September 2010 was 100.3 and 68.6 GW correspondingly. During the same time slot, through the exchange contracts were sold and purchased 128 GW in the first price area and 18.3 GW in the second price area of the market (ATS 2010). The most demanded exchange contract traditionally are peak and half peak contracts which contain less quantity of energy supplied in addition to capacity under the contracts.

7.1.5 *Bilateral contracts for capacity after 2011*

The transient period of the capacity market in Russia completed at the beginning of 2011. According to the government regulations, the current model of the capacity market is replaced with the new model of long-term capacity market in which the incentives of the market participants to enter the bilateral contracts for capacity are diminished to a considerable extent. The point is that in the new model of the market the rules of the price definition in the capacity auctions are different. If in the transient model of the capacity market the majority of contracts were concluded because of the gap between the generators' and consumers' prices for capacity then in the long-term model of the market this possibility is fully eliminated. The price for capacity will be defined by the SO four years ahead in the marginal auctions of supplier's offers in the result of which the single equilibrium prices for the generators and the consumers in every area of free power flow will be applied. Therefore, all generators with low-price capacities will be getting payments for their capacity at the higher prices determined by the more expensive generators during the auctions and will become less interested in entering the bilateral contracts. Also, as opposed to the transient model of the market in which the price of capacity in the auctions was increasing from the *initial* to the *actual* price at the proceeding of a year, the price of capacity selected in the auctions in the new model will not be changing during the years. Definitely, that will also prevent the market participants from conclusion of the contracts the main purpose of which is to hedge against price volatility.

However, the new rules of capacity market foresee retention of bilateral contracts for capacity. Delivery of energy under a contract for capacity is now optional. The Exchange forfeits its mandatory status and continues existing as an auxiliary mechanism of counteragents' search. Also, according to the new rules, an amount of capacity sale in contracts for a generator should not exceed his volumes of capacity selected in the competitive auction and actually delivered to the market. In turn, consumers will be allowed to purchase through the contracts only the volumes of capacity which are necessary to cover their actual consumption minus 1MW. In addition to that, the new rules restrict entering the contracts between the counterparties located in different areas of free power flow. Therefore, in the conditions imposed by the new market, the contracts can be concluded before the competitive auctions in order to hedge the price changes risks mainly. Entering the contracts after the auction can be useful if the counterparties want to mitigate the credit risks.

8 Participation of the new stations in the capacity market

8.1 Selection of new capacities in auctions 2009-2010

The capacity price offers submitted by the new power stations (put into operation after 2007) to the auctions of capacity selection for 2009 and 2010 years were examined by the regulators for the purposes of their economical validity. In the issue of evaluation, the capacity price in the offers could have been accepted, declined or corrected. The Market Council defined its own “fair” price for the each of the new stations based on the costs of typical power plant construction and then compared it with the price offer of a generator. If the price proposed by a generator was higher than the “fair” price then his price was declined and during next year a generator was getting the payments for capacity in accordance with the “fair” price. If the capacity price proposed by a generator was lower than price stated by Market Council then the price of a generator declared valid.

Table 8. Example of capacity prices for different types of new generation in 2010 defined by the methodology of the Market Council

Type of generation	Capacity, MW	First price area Price, [RUB/MW per month]	Second price area Price, [RUB/MW per month]
Gas generation	250	526450	703870
	200	620200	829660
	150	751500	1005900
Coal generation	250	1169300	1466300
	200	1265800	1587700

In 2010 the Market Council approved 74 capacity price offers of the new generators. Only one price offer was declined. The highest price accepted by the Market council constituted 820000 RUB/MW per month and the lowest price is 62700 RUB/MW per month.

8.2 Participation of the new Nuclear and Hydro stations in the Capacity market

The new nuclear and hydro stations constructed under private investment projects selected by the government conclude long-term agreements of capacity supply. Also, these agreements are allowed for the nuclear stations of the state corporation “Rosatom” that are under construction in accordance with the government program 2009-2015 and the hydro stations of the JSC “RusHydro”. A contract period is 20 years while the actual payback period is 25 years. The price in an agreement is defined by the Federal Tariff Service of Russia. During the future auctions, capacity of these stations will be taken into account as a price accepting offer.

8.3 Contests of investment projects

The regions with forecasted deficit of generation can apply to the government on issue of a new station construction to cover this deficit in the future. The SO defines the location and terms of construction of a new station and organizes a contest of investment projects. A contest is organized only if there is no other source of financing could be attracted. If a contest is organized, the SO forms a special commission which considers the offers of investors willing to participate in the competition. In the offer, an investor indicates parameters of a new station and the price he wants to get for energy and capacity produced by the station. From the other side, the commission defines a maximum cost of an investment project on a basis of technical-economical calculations and by comparing of costs of analogous projects. Then, the commission uses parameters of the station submitted by an investor in his offer in calculations of the project's costs and set the "fair" tariff for the station or modernized unit. The project of a new station can be accepted only if its overall cost does not exceed a maximum cost of an investment project defined by the commission.

The winner of a contest is a project that meets all above mentioned conditions and that has the lowest costs of construction. An investor takes obligation to build up and put into operation a new station or modernize the existing units at predetermined terms. In order to guarantee fulfillment of the project an investor enters into agreement with the SO. The station constructed under a contract is prohibited from participating in the competitive auctions and entering the bilateral contracts for capacity. Instead, the station receives payments for electricity and capacity at the price specified in the agreement with the SO and gets additional payments for the forming of technological reserve. The last component will be paid by the SO which collects it from the market participants in the payments for dispatching control. The total value of payments for the forming of technological reserve could be roughly estimated as the average costs of borrowed and own assets attracted by an investor for the project.

For an investor signing of the contract with the SO is a risk-bearing event. It means that he starts exposing himself to many risks. Some of these risks are listed below:

- Strict requirements of the SO to set out a generating object in terms stated in the agreement. High value of penalties for the delay.
- Risks of monetary losses caused by non-ability to participate in the markets where the prices could be more attractive
- Risks related to incorrect forecast of fuel costs (for instance, significant increase of fuel costs will cause tangible losses of revenue)
- Legislation changes

However, an organizer of a contest mitigates the risks of investors. For instance, it carries out a preliminary technical-economical calculation of the project which allows investors for more precise estimation of their costs. Besides, the SO also works out all technical and legal aspects of connection to the national grid and estimates its preliminary costs for an investor. The holder of the competition settles out all legal questions related to land area where a new station will be constructed and reconcile a dispute with local authorities.

8.4 Capacity Delivery Agreements

New heat stations which are under construction could hedge a significant part of their future returns by signing the contracts with floating price called "Capacity delivery agreements". These agreements were invented by the Ministry of Economical Development that wanted to get guarantees of new capacities' construction from the private generating companies. After signing an agreement, a generator is not participating in long-term competitive capacity auctions but gets guaranteed payments for his capacity at the contract price defined in accordance with the directive № 238 "On definition of price parameters of capacity trade on the wholesale electricity (capacity market) of the transition period". The contract price determines in such way to compensate a significant part of the capital and operating costs of a station and cover its tax allocations and grid connection costs within the payback period of 15 years. However, an investor is allowed to receive payments under an agreement at the proceeding of the first 10 years only which corresponds to returns of 66.6% of his total investments in construction and operation of a station. It is planned that the rest of the costs will be compensated throughout profits from the spot-market of energy.
The directive № 238 states the base rate of return on the invested capital equal to 14-15%. However, this value will be recalculated each year by regulators in accordance with average rates of returns on the government bonds. Non-fulfillment of Capacity Delivery Agreement means for a generator paying back 25% of the investment program costs and undertaking of obligation to submit in the future auctions the price accepting offers only.

The signing campaign was organized during the years 2009-2010. In November 2010 the contracts were finally signed by the generating companies of Russia. The total volume of capacity put into operation under the contracts between 2007 and 2017 will be 30475 MW. Presumably, it will cover most of capacity deficits in the market in the upcoming years.

8.4.1 *The risks under Capacity Delivery Agreement*

Entering Capacity Delivery Agreement is a preferred alternative for a generator to participation in auctions of capacity selection where "price caps" can be applied. Having a contract, a generator is hedged against changes of capacity price in the future auctions because he is receiving stable returns under a contract during 10 years. However, after this period of time a generator starts participating in capacity auctions on the grounded basis with other participants. That means possible losses of a generator and increase of the payback period if price of capacity defined in the future auctions will be too low in comparison with the price under an agreement. On the other hand a generator gets excessive revenues and shortens the payback period if prices in the future auctions will be higher then the price under a contract.

The terms of the long-term Capacity Delivery Agreements also imply that an investor may leave a contract before its expiration and start selling his capacity in the auction if he finds it profitable. However, as it was mentioned earlier, at present almost all new generation have signed Capacity Delivery Agreements and will not be participating in price formation during the future auctions in the market. It means that, capacity prices in the market will be driven mainly by generators that have been operating there for years. Most of them are old generation with cheap tariffs and that means that price in the future capacity auctions should be relatively low. But old generators also might try to get additional revenues by submitting high price offers that, in turn, increase the risks of "price caps" introduction. There is a vague hope that in these conditions an investor will decide to leave beneficial Capacity Delivery Agreement earlier than its expiration date.

Based on some of the assumptions mentioned above, we try to estimate the risk of a made-up gas generation with installed capacity 200 MW from entering Capacity Delivery Agreement. For this purpose we formulate three scenarios:

1. Optimistic scenario that implies that a generator keeps receiving capacity payments at the price stated in an agreement at the proceeding of last 5 years of payback period. In this scenario we also consider the case when an investor postpones a station's startup by one year.
2. *Pessimistic scenario* which implies that a station's startup is postponed to more than one year. In this case we assume an investor is penalized at the rate of 25% of investment program's costs and sells capacity in auctions at the price 10-50% lower than the price under an agreement.
3. *Realistic scenario* when the generator sells capacity at the price determined in the agreement during the first 10 years and at the price 10-50% lower during the last 5 years

For each of the following scenarios we define an expected net present value of a project at the end of 15th year and the actual payback period. During calculations of the prices under an agreement we make an assumption of the fixed rate of returns 14% which in reality is not and depends on profitability of the government bonds. The issue of the impact of the government bond rates on the rate of profit under Capacity Delivery Agreements will be discussed later in more details. The cost of connection to the national grid is assumed to be 70 million rub, which roughly corresponds to the costs of the new power transformers installation. The straight-line depreciation with rate 1/15=0.0667 was applied to get the values of the annual property tax allocations. Indexation of the operational costs was carried out accepting the constant rate of inflation 7%.

The monthly capacity prices of the station under an agreement presented in the table 8. The prices were calculated in accordance with price parameters established in the directive № 238 for this type of generation. An interesting feature of this cash flow is that its main component that assures returns on the invested capital is kept almost constant throughout the years. The point is that the "body" of the capital investments returns gradually to an investor through the annual payments that are constantly increasing by 19%.The sum of these payments in the end of the payback period is equal to the amount of initial capital investments. As opposed to that, the returns on capital decline over the time of the payback period. They are estimated for each year as a cross-product of the capital investments left to be compensated and the rate of returns on investments. The sum of these two component yields a cash flow which is around constant during the whole payback period. The next price component is the property tax allocations is reducing over the time but annually increasing operational costs that are indexed in accordance with the inflation rate 7% stipulate, in total, the growth of the finite capacity prices from year to year.

Table 9. Capacity price under an agreement for the made-up generator with installed capacity 200 MW

Year	Price, RUB/MW per month
1	655540
2	657570
3	660040
4	663010
5	666520
6	670640
7	675430
8	680970
9	687340
10	694660
11	703020
12	712560
13	723450
14	735850
15	749970

8.4.1.1 Optimistic scenario

In this scenario we consider a situation when the generator with installed capacity 200 MW receiving payments for his capacity at the price under an agreement at the proceeding of the whole fixed payback period 15 years. An important assumption done should be noted before. The point is that, during estimation of the net present value of the project the value of initial investments is intentionally cut by 25%. This allows excluding impact of the spot market on the results of calculations and to define the values of returns on capacity only. Proceeding from that, we multiply the initial capital investments Io by $Kspot$. The value of the net profit under the project at the end of the payback period in the optimistic scenario is defined in accordance with the following equation:

$$NPV = Kspot \cdot (-Io - \sum_{i=1}^{15} OPEX_i - \sum_{i=1}^{15} Tax_i) + Kaux \cdot (\sum_{i=1}^{15} AR_{dis\,i} + + Kspot \cdot \sum_{i=1}^{15} OPEX_i + Kspot \cdot \sum_{i=1}^{15} Tax_i) \qquad (1)$$

where,

Io is the capital investments in construction and connection to the grid,
$OPEX$ is the value of operational expenses in year i,
Tax is the property tax allocations in year i,
$Kspot$ is the spot market coefficient,
$Kaux$ is the coefficient which takes into account auxiliaries' consumption of capacity at a station
AR_{dis} is the discounted value of allowed returns on invested capital under the project in year i.

Estimation of the actual payback period is given graphically in Figure 18. The breakeven point is found as a point on the figure in which the NPV shifts from negative to positive values. This gives the value 12.4 years which is, in fact, smaller than the payback period of 15 years stated in the decree for all investment projects.

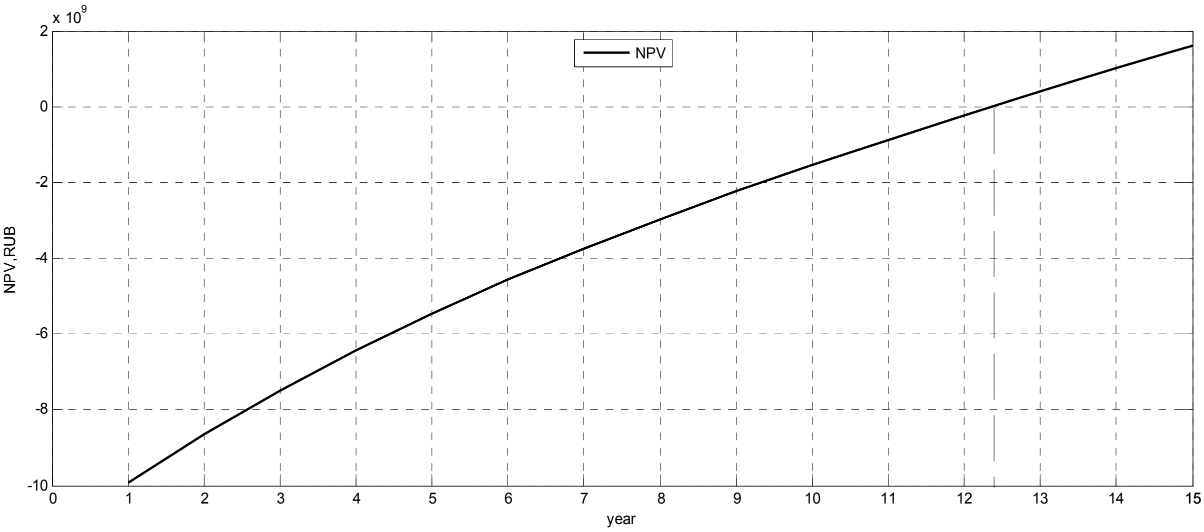

Figure 18. The net present value curve of the project and the real payback period in optimistic scenario

In accordance with terms of Capacity Delivery Agreements an investor is allowed to postpone a station's startup by one year. In this case he will not be penalized but the payback period of 15 years also will not be reconsidered. For an investor this mean that he will be receiving capacity payments under an agreement in the course of 9 years only.

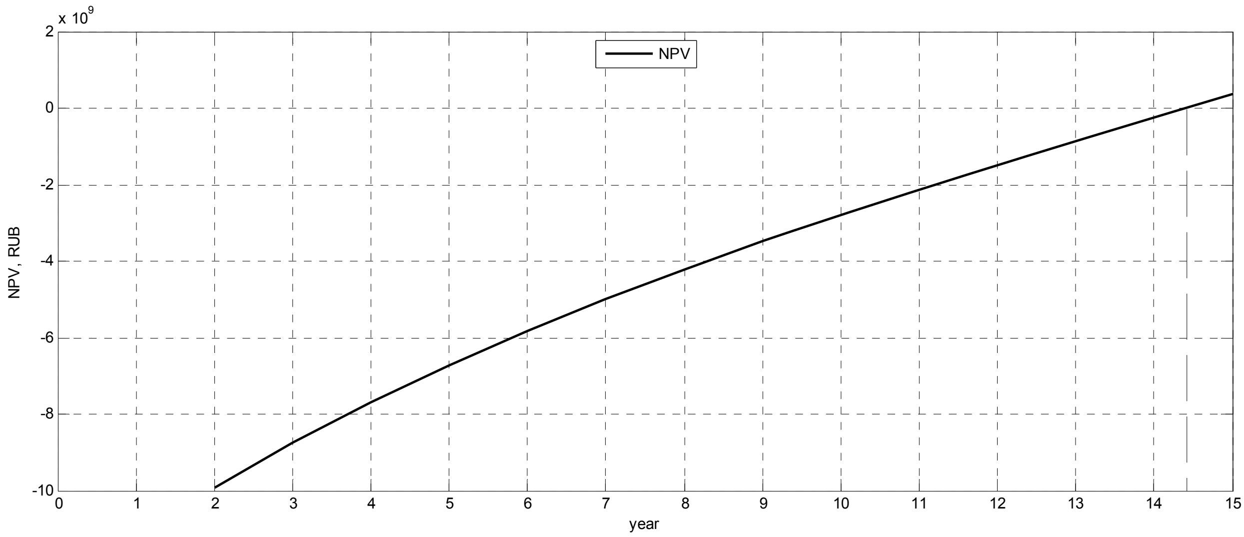

Figure 19. The net present value curve of the project and the real payback period in optimistic scenario when a startup of the station is delayed by one year

As it could be seen in Figure 19, the real payback period is 14.4 years. In simple words, an investor could barely get back his means at the end of the payback period stated under an agreement. The total profit of an investor is the NPV of the project at the end of15th year which is equal to 0.3627 billion RUB.

For others scenarios we continue keeping in mind the assumption that the station always receive from the spot-market enough profit to recover 25% of the investments. Thereby, as what we could see in the next examples is how changing of capacity price will affect on the payback period of 75% of initial investments.

8.4.1.2 Pessimistic scenario

In *Pessimistic scenario* we assume that a station's startup is postponed to a third year. In this case an investor will be penalized at the rate of 25% of the investment program's costs and obliged to sell capacity at the price of auction which is assumed to be 10, 30 and 50% lower than the price under an agreement.

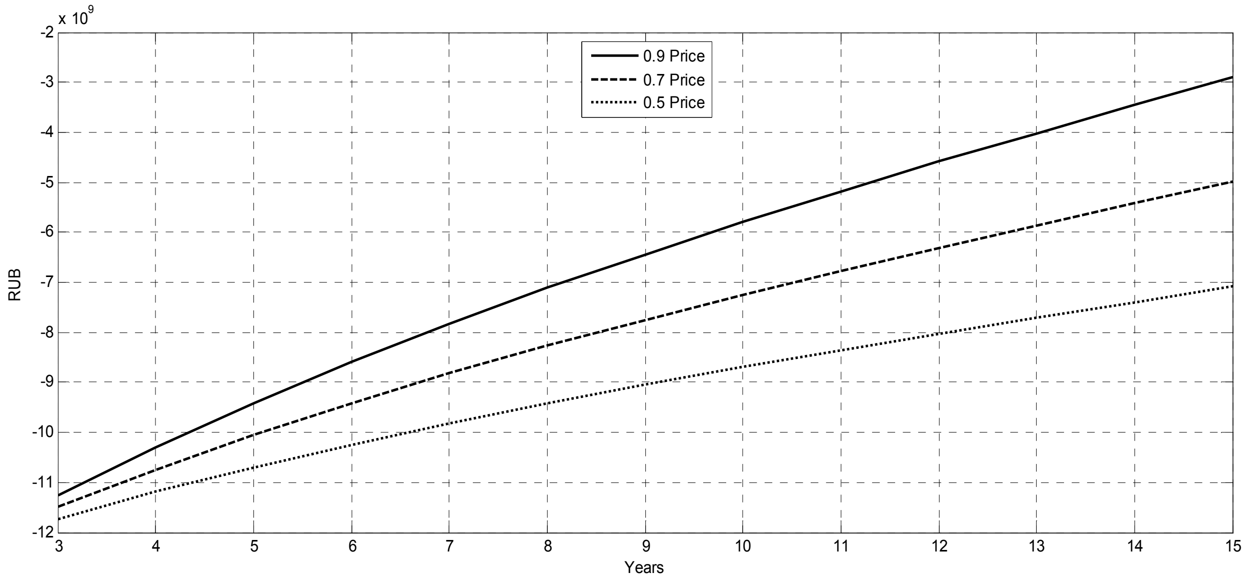

Figure 20. The net present value curve of the project and the real payback period in pessimistic scenario

The payback period in this scenario is not defined. As one could clearly see it from the figure the NPV after 15 years takes only negative values and an investor in station's construction will incur significant losses under the project.

8.4.1.3 Realistic scenario

For the realistic scenario we accept that the capacity price in the auctions during the last 5 years is 10, 30 and 50% lower than the price under an agreement. The NPV curve constructed for each of the case is depicted below in Figure 21.

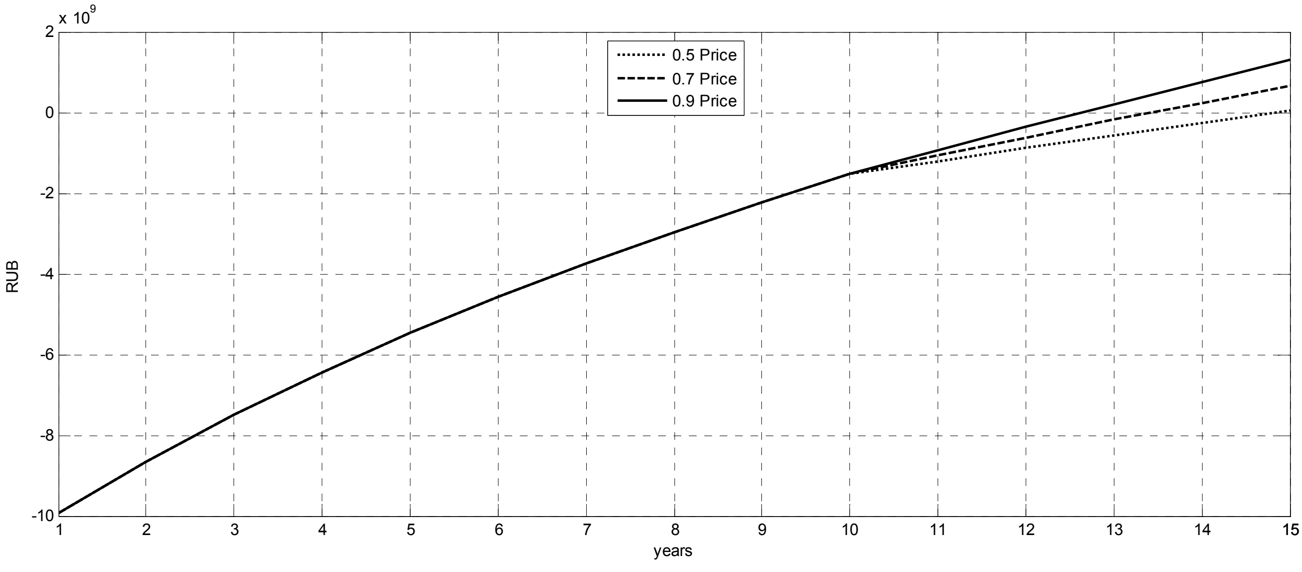

Figure 21. The net present value curve of the project and the real payback period in realistic scenario

As it can be seen from the Figure 21, if the price in the auctions will be around half the price under Capacity Delivery Agreement during the last 5 years, the new generator will barely receive 75% of his investments back through capacity payments after the 15 years period and will not be able to make any profit under the project. Further reduction of the price in the future auctions means unprofitability of the project and prolongation of the payback period to a long date. On the other hand, 10 and 30% drop of price in auctions in the last 5 years still imply getting of some profit on construction of the station after the 15 years period.

Comparison of NPVs in different scenarios is made in appendix 5

8.4.2 *Impact of government bond rates changes on profit rate under Agreements*

The rates of returns on invested capital are not fixed throughout the payback period under Capacity Delivery Agreements. Instead, they depend on changes of rates of the government bonds having the maturity date from 8 to 10 years. Re-estimation of profit rate under Capacity Delivery Agreement is carried out annually by the commercial operator that uses data of bond trades obtained from the "Moscow Inter Bank Currency Exchange".

The rate on invested capital under Capacity Delivery Agreement is defined by the commercial operator through the equation (2.1) taking into taking into consideration previous emissions of stocks done by generating companies. In this section we will examine the impact of government bond rates changes on the rate of profit under Capacity Delivery Agreements. For this purposes, we choose three time series of prices of the government bonds with maturity dates from 9 to 11 years placed at the "Moscow Inter Bank Currency Exchange" between 2002-2005 years. Table 10 contains the main features of these bonds.

Table 10 Basic indicators of the government bonds with maturity dates 9-11 years

Name of the bond	Bond type	Nominal value, RUB	Date of issue	Date of maturity	Coupon, %	Coupon frequency, times per year
26198P	Fixed rate coupon	1000	09.10.2002	02.11.2012	6	1
46002	Graduated rate	1000	05.02.2003	08.08.2012	8	2
48989N	Graduated rate	1000	16.02.2005	03.08.2016	7	4

The time series of net prices of the chosen bonds are depicted below in the Figures 22-24.

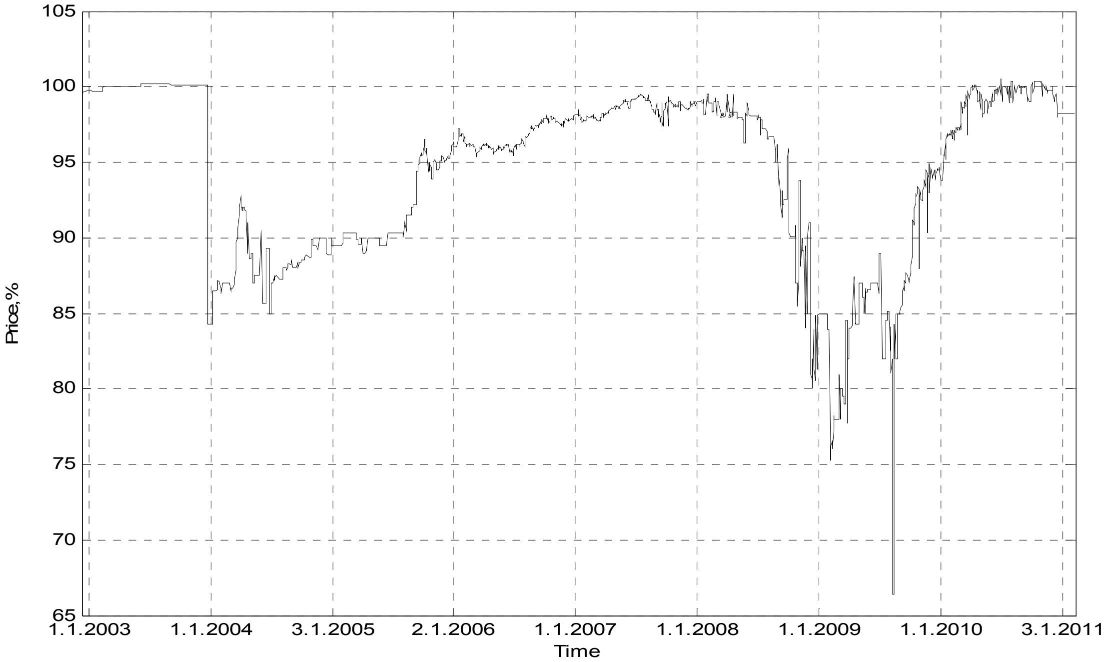

Figure 22. Prices of the government bonds 26198P from 11.12.2002 until 4.2.2011 (2128 values)

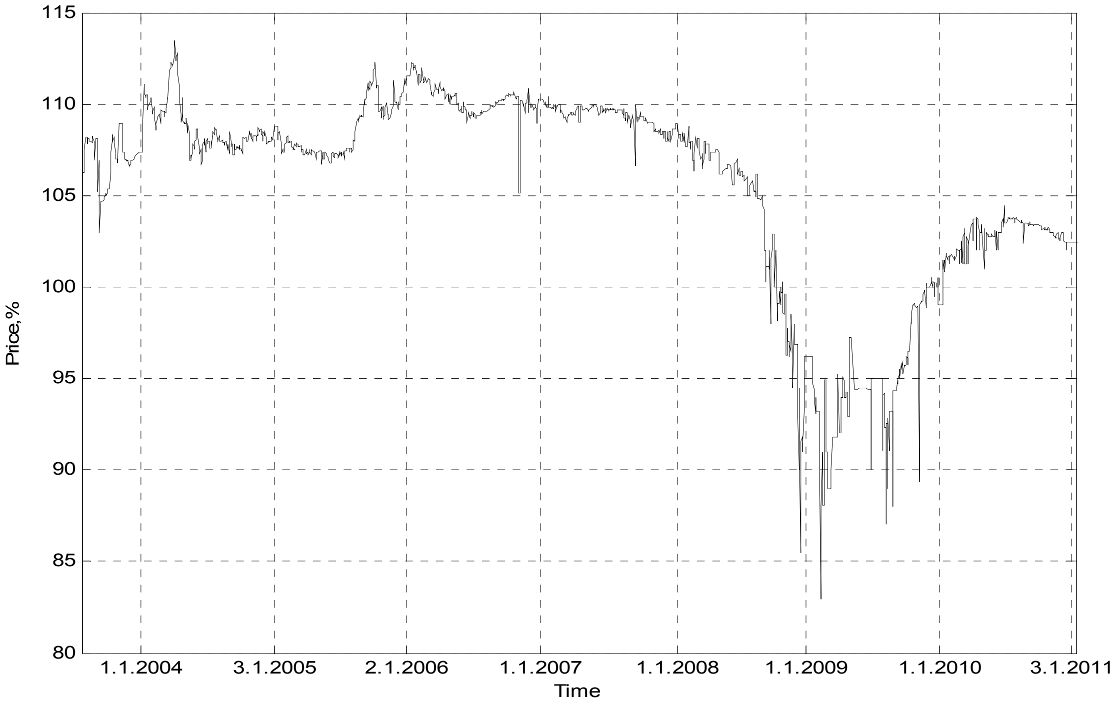

Figure 23. Prices of the government bonds 46002 from 23.7.2003 to 4.2.2011 (1968 values)

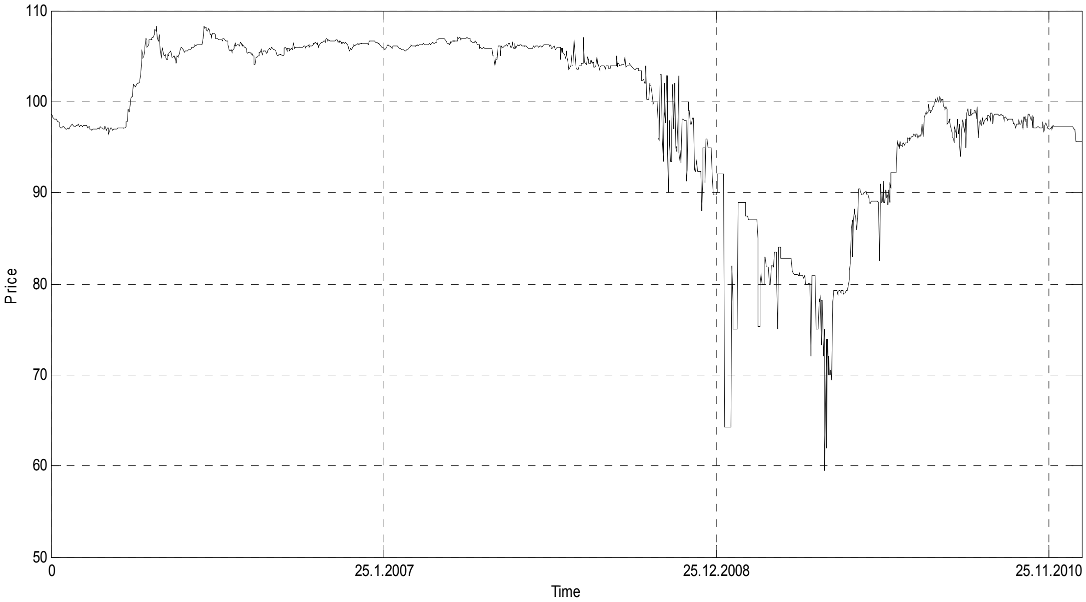

Figure 24. Prices of the government bonds 48989N from 25.02.2005 to 04.02.2011 (1551 values)

Internal rates of returns (IRR) on the government bonds that are of particular interest can be obtained from the original time series of prices through the simplified formula:

$$r = \frac{f \cdot A + \dfrac{A - P}{T}}{\dfrac{A + P}{2}}\ , \qquad (2)$$

where

A is a face value of a bond,
P is current price of a bond,
f is a coupon value,
T is time to maturity date

The time series of internal rates of returns (yields to maturity) obtained through the equation (2) for the government bonds 26198P are shown in the figure below. We will keep using the government bonds 26198P as an illustrative example during further work.

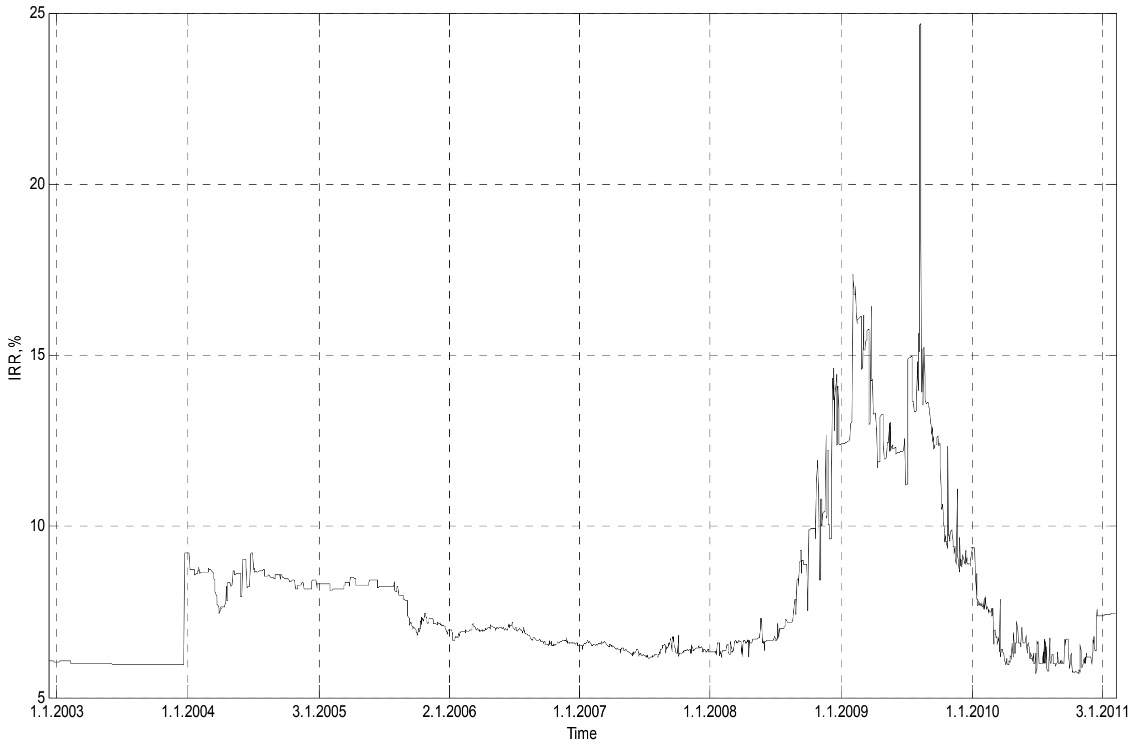

Figure 25. Internal rate of returns (IRR) on the government bonds 26198P

On the next step, additional transformations of the time series are needed. First, we "filter" the original time series of IRRs applying the method of moving average smoothing. This will let us disregard the outliers containing in the original time series of IRRs.

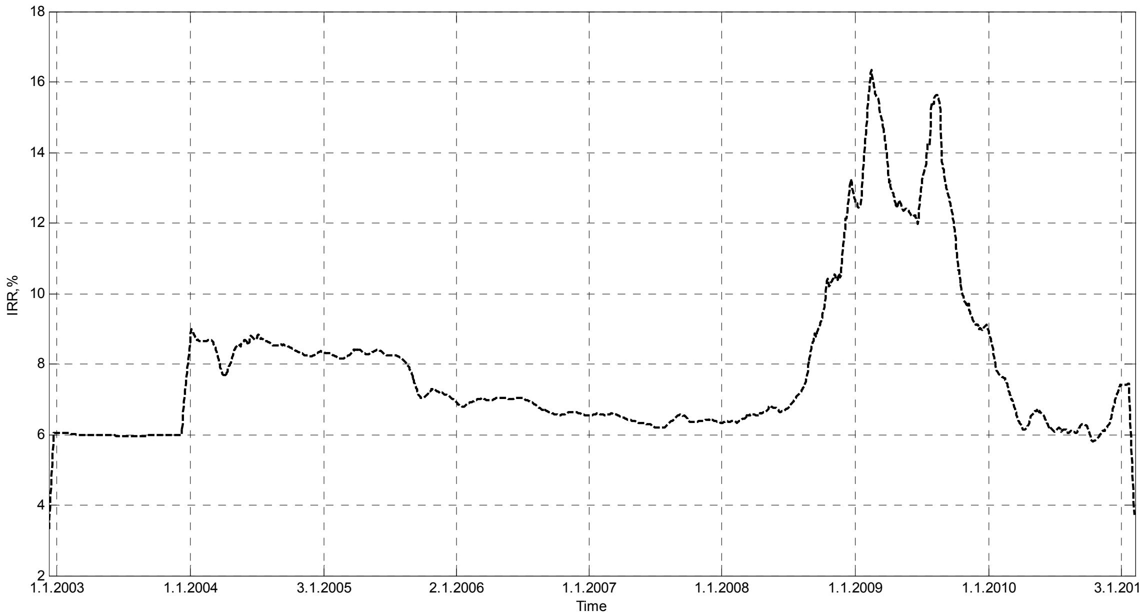

Figure 26. Example smoothed time series of bond rates (time span 20 days). Government bonds 26198P.

All time series of the bond rates have different starting dates. Thereby, we use the sample from each of the time series corresponding to the observable period of time from 25.02.2005 to 04.02.2011. For verisimilar results, we also need to modify the samples of the time series by exclusion the range of data which corresponds to the world crisis period.

It could be seen in the Figures 22-24 that the significant drop of bond prices (increase of bond rates) began in July-August 2008. In March 2010 the level of prices returned to initial level of 2008. Proceeding from that, we exclude from analyze the part of the time series between 01.07.2008 and 31.3.2010 implying that observing changes of bonds rates are happening in times of the stable economy only. The modified time series for the bond rates is presented below in Figure 27.

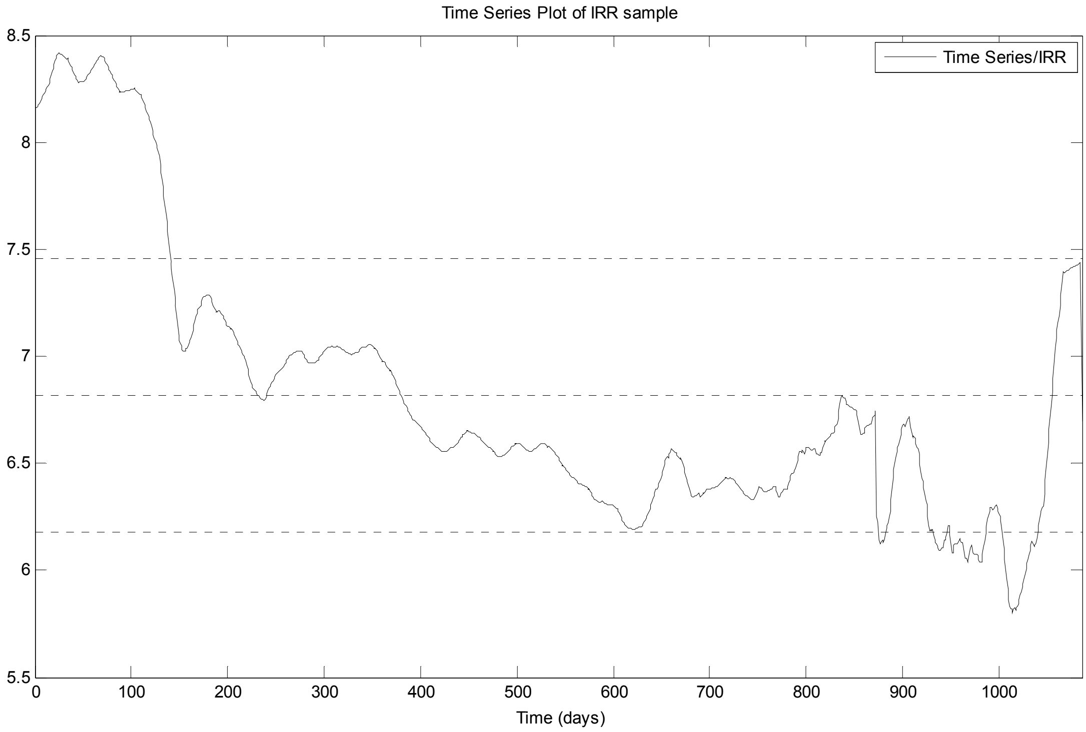

Figure 27. Mean value and standard deviation of the modified IRR time series of the bonds 26198P

Estimation of mean value and standard deviation of every of the modified bond rates time series is shown in Table 11.

Table 11 Estimated mean values and standard deviations of the bond rates

Bond name	Mean value of internal rate of return, %	Standard deviation of internal rate of return, %
26198P	6.8158	0.6385
46002	5.5304	0.3763
48989N	5.9179	0.4856
Average values:	**6.0878**	**0. 5001**

Average values of standard deviation from the bottom row of the Table 11 now can be used to define the limits of the government bond rates changes. Addition and subtraction of standard deviation from the mean gives the upper and lower limits of the bond rates changes which are 6.588% and 5.5877% correspondingly. Virtually, these values could be used now as a broad measure of risk. By substituting these values in the formula (2.1) for the rate of return under Capacity Delivery Agreements we can define the possible limits of the project interest rates changes:

$$ROR_{upper} = \frac{(1+0.14)\times(1+0.0659)}{(1+0.085)} - 1 = 0.1199,$$

$$ROR_{lower} = \frac{(1+0.14)\times(1+0.05587)}{(1+0.085)} - 1 = 0.1093$$

Therefore, the rate of return on invested capital under Capacity Delivery Agreements can vary from one year to another between 10.93% and 11.99 % for the generating companies that attracted additional capital by stock emissions and 11.91% and 12.97% for those companies who did not.

9 Conclusion

It can be concluded that the main goals of the power reform Russia basically have been achieved. The necessary inflow of investments in the power sector was insured first by privatization of generating assets and launching of the markets of energy and then by opening of capacity market. Nevertheless, it is hard to say that all investments made into the power sector of Russia were market-driven.

The nodal price system used in the physical markets of energy in Russia is an effective mechanism of a "fair" price definition in the conditions of weakened transmission capacities. However, its advantages of showing the "places" where new investments are most favorable to be, potentially, can be restricted by strong market regulation. In addition, the nodal price system impedes development of the market of energy derivatives in Russia. Incentives of entering the forwards and futures contracts to hedge against price changes are still reduced because of unsolved problem of the basis risk for counterparties under a contract. Perhaps, in absence of large investments in network infrastructure, introduction of the market of Financial Transmission Rights which is on the list of the reform would mitigate this risk in the future.

Attraction of investments in construction of new capacity reserves has been implemented not in a market-based manner. Capacity Delivery Agreements with new private heat stations and long-term agreements with new nuclear and hydro stations, virtually, represent long-term interest-bearing loans taken by the government from generating companies for construction of new capacities. Gradual redemption of loan to generators is done by end-users which are charged with capacity payments. The amount of capacities constructed under the contracts should cover forecasted deficit of capacities in the market during the next 10 years. In all likelihood, there will be no need for new massive investments in the Russian generation in the nearest future. If some deficit of megawatts appears in the future, the regulators will organize the contest of investment projects and pick up an investor with the cheapest project costs to fill the capacity gap.

The first auctions of capacity selection organized by the new rules of the long-term capacity market yet for one year ahead, have revealed how the most "expensive" and inefficient capacities might be treated in the long-term market model. The generators that were not selected in capacity auctions but still needed for reliable operation of the system got regulated tariffs that in many cases exceeded the market price level. Most probably, this will not take place in the future auctions when more capacities will be constructed under Capacity Delivery Agreements but it is still an open question. On the other hand, capacity price offers of old generations will be withholding by application of "price caps". The values of "price caps" defining the overall capacity market price level will be re-estimated annually by regulators. It is hard to infer now what capacity market price level will be in the future.

The future plan in capacity market is to create competition in demand and emphasize competition between generators by developing network infrastructure and merging areas of free power flows. This would allow for gradual escape from application of “price caps” which put obstacles on the way to competitive relationships in the capacity market of Russia.

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Appendix 1

Methodology of the Market council used to evaluate capacity bids of new station in the auction 2010

Capacity price is calculated proceeding from capital and operation expenses of typical generating objects applying reasonable indicators of profitability and payback periods of invested capital. The special methodic used by Market Council for the purposes of price evaluation includes definition of allowed profit of the generator obtained from capacity sale:

$$\Pr ofit_k = \left[\frac{\left(C * (2n - 2k + 1) / 2n \right) \cdot WACC}{1 - H} + C / n \right], \qquad (1.1)$$

Where

k=1,…,n;

$\Pr ofit_k$ is allowed profit of generator obtained form capacity sale in year *k*;

WACC is weighted average cost of capital (standard value of 9.6% used in equations as interest ratio)

C is capital costs of the generator discounted to the year of auction

H is profit tax (equal to 20%)

n is number of years the generator participates in investment project (15 years)

Capital costs are determined on the basis of normative values of specific capital expenditures taking into account equal distribution of investments through the years (it is accepted that gas stations could be constructed in 3 years and coal station – in 5 years):

$$C = k_{c\lim ate} \cdot k_{seismicity} \cdot C_{bas} \cdot N \cdot \left(1 + WACC\right)^{\mathrm{red}} + TC \qquad (1.2)$$

Where, *N* - rated capacity of power plant;

red – reduction degree (1 - for gas generation, 2 - for coal generation);

TC- actual expenses for technical connection of power plant to the main grid;

C_{bas} - basic parameter of capital investments in 1 kW of rated capacity determined by Market Council on the basis of statistical data collected from typical capital expenses of most power plants. This parameter is different for different power plants and depends on the type of power plant and its rated capacity:

1. For gas stations with installed capacity more than 250 MW C_{bas} is taken equal to 33000 RUB/kW* installed capacity

2. For gas stations with installed capacity less than 250 MW and more than 150 MW C_{bas} is taken equal to 39250 RUB/kW* installed capacity

3. For gas stations with installed capacity less than 150 MW C_{bas} is taken equal to 48000 RUB/kW* installed capacity

4. For coal stations with installed capacity less than 225 MW C_{bas} is taken equal to 67400 RUB/kW* installed capacity

5. For coal stations with installed capacity more than 225 MW C_{bas} is taken equal to 62000 RUB/kW*installed capacity

$k_{seismicity}$ - seismicity factor; $k_{c\lim ate}$ - climate factor

Present Value of all capital flows PV during the payback period *n*:

$$PV = \sum_{k=1}^{n} \frac{\Pr ofit_k}{(1+WACC)^{k-0.5}} - \frac{V^{Market}}{(1+WACC)^n} \quad , \tag{1.3}$$

Where

V^{Market} is cost of the generating equipment in the beginning of the year following after the last year of the payback period.

Reasonable value of monthly payment for 1 MW of capacity is defined as annuity from present value of cash flows plus operational expenses and property tax allocations:

$$SN = \left[\begin{array}{l} \left(\left\{ \dfrac{PV \cdot WACC \cdot (1+WACC)^n}{(1+WACC)^n - 1} \cdot (1+k_{\inf lation}) + TF_k \right\} \cdot k_{spot} / N + \Delta p + \Delta SN \right) / 12 + \\ + C_{operat} \cdot k_{spot} \cdot k_{operat} \end{array} \right] \times \quad , \tag{1.4}$$

$$\times \frac{\sum_{s_{2010}} KC_{s_{2010}}}{(13 - s_{2010})}$$

where

$k_{\inf lation}$ is index of consumer prices in the year previous to the year of auction;

TF_k is tax on funds in year *k;*

k_{spot} is the spot-market coefficient. This coefficient is used in order to take into account the profit obtained by a station as a result of electricity sale. For different types of stations situated in different price areas k_{spot} has a different value:

- 0.75 for gas generation located in the 1st price area;
- 0.8 for coal generation located in the 1st price area;
- 0.945 for the generation located in the 2nd price area;

N is installed capacity of power unit [MW];

Δp and ΔSN are compensations of spot-market profit deviation and capacity price deviations (caused by mismatch of seasonal factor) that took place during the year before auction

C_{operat} is standardized value of operation costs (80000RUB/MW*month for gas stations; 120000RUB/MW*month for coal stations)

k_{operat} is factor reflecting the growth of operational expenses (0.934)

KC is the season factor for the first month s in which the station starts capacity delivery in the year preceding the year for which the competitive capacity auction is held.

Appendix 2

Methodology of price calculation in Capacity Delivery Agreements

The methodology states the following shares of summarized costs compensation via long-term capacity supply agreement for different types of stations:

- For the gas stations located in the 1st price area of the wholesale market with installed capacity more than 250 MW only 71% of total costs will be compensated via capacity sale. Other 29% of costs is planned to be refund throughout electricity sale
- For the gas stations located in the 1st price area of the wholesale market with installed capacity less than 250 MW and more than 150 MW only 75% of total costs will be compensated by capacity sale
- For the gas stations located in the 1st price area of the wholesale market with installed capacity less than 150 MW only 79% of total costs will be compensated via capacity sale
- For all gas stations located in the 2nd price area of the wholesale market 90% of total costs will be compensated via capacity sale
- For all coal stations located in the 1st price area of the wholesale market 80% of total costs will be compensated via capacity sale
- For all coal stations located in the 2nd price area of the wholesale market 95% of total costs will be compensated via capacity sale

After 3 and 6 years from the moment of the station's startup the commercial operator re-estimates the share of compensated costs that reflects forecasted profit received from the spot-market.

According to the methodology, all actual costs related to technological connection of the stations to the national grid and tax allocations are taken into account in the capacity price calculation.

Table 2.1 Capital investments for construction of 1 kW of capacity stated in the methodology

Gas generation		Coal generation	
Installed capacity, [MW]	Capital investments, [RUB/kW]	Installed capacity , [MW]	Capital investments, [RUB/kW]
>250	28770	<225	53450
250-150	34400		
<150	41850	>225	49175

Depending on the station's type, its location and possibility of reserve fuel application the increasing and reducing coefficients are applied to the value of capital investments.

Operating costs in 2010 are stated equal to 80000 RUB/MW per month for the gas generation objects and 123000 RUB/MW per month for the coal generation objects correspondingly. The value of operating costs is a subject of indexation from the 1st of January 2010 to the 1st of January of the year in which the station is put into operation.

The calculated price of capacity should guarantee a predetermined share of returns of capital and operating costs, property tax and actual costs of grid connection. Besides, the methodology foresees application of the coefficient k_{aux} that reflects power consumption of the station for its own needs:

- For the generating object of gas generation k_{aux} is 1.033
- For the generating object of coal generation k_{aux} is 1.069

The commercial operator recalculates the rate of return on invested capital every year according to the equation:

$$ROR_i = \frac{(1 + ROR_{base}) \times (1 + ROR_i^{government\_obligations})}{(1 + ROR_{base}^{goverment\_obligation})} - 1, \quad (2.1)$$

where

ROR_{base} is base rate of return on invested capital. This value is taken equal to 15% for those suppliers that didn't increase capital by allocating additional stocks and 14% for the others.

$ROR_{base}^{goverment\_obligation}$ is base rate of return on long term government obligations. That value is captured at level 8.5%

$ROR_i^{government\_obligations}$ is average rate of return on long term government obligations in year *i* with maturity date not less than 8 years and no more than 10 years.

The value of *ROR* fluctuates in accordance with the profitability of the government's long-term obligations. In calculations of $ROR_i^{government\_obligations}$ the data from the auctions of federal bonds at the stock exchange "The Moscow Interbank Currency Exchange" is used. An order of $ROR_i^{government\_obligations}$ calculation is stated in separate methodology under the decree № 238 "On definition of price parameters of capacity trade" issued by the Ministry of Economical Development of Russia in April 2010.

The future value of capital costs reduced to the first year of a station startup is calculated by the commercial operator via the following equation:

$$FV_{capex} = Capex_{base} \cdot k_{spot} \cdot k_{reserve} \cdot k_{seismicity} \cdot k_{c\lim ate} \cdot k_{profit} \cdot (1 + ROR_{-1})^{N-st}, \quad (2.2)$$

Where
$Capex_{base}$ is the value of capital investments in construction of 1 kW of capacity stated in the methodology
k_{spot} is the coefficient that indicates the share of summarized costs allowed to be compensated throughout the capacity sale
$k_{reserve}$ is coefficient that takes into account capability of the generator to use reserve fuel
$k_{seismicity}$ is the seismicity factor (takes value from 1.06 to 1.13)
$k_{climate}$ is the climate factor (takes values from 1 to 1.3)
k_{profit} is the coefficient which reflects the profit obtained from the electricity (capacity) market after payback period's end (0.9 for the stations located in the 1st price area of the market and 0.95 for the stations located in the 2nd price area)
ROR_{-1} is the average weighted rate of return on invested capital. For gas generation this value represents the average weighted rate of return during 1.5 years prior to a station startup. For coal generation this value indicates the average weighted rate of return during 2.5 years prior to a year of capacity delivery.
N_st is equal to 1.5 for the gas generation and 2.5 for coal generation

For the first year of capacity sale, the value of reimbursable expenses calculates as follows:

$$R_1 = FV_{capex} + TC\,, \tag{2.3}$$

Where
TC is the cost of technological connection to the national grid

The value of reimbursable expenses for each year is determined by the equation:

$$R_i = R_{i-1} - r_{i-1} + (ROR_{i-1} - ROR_{i-2}) \cdot (1 + ROR_{i-1}) \cdot R_{i-1}\,, \tag{2.4}$$

Where
r_i is the value of annual return (in constant real expression) on invested capital taking into account 15 years of payback period;
R_i is the value of reimbursable expenses remained in the year *i*

In rough estimations, when the value of $ROR_i^{government\_obligations}$ is constant through years a simple geometrical progression $r_i = r_{i-1} \cdot k$ could be used to calculate the size of annuities. Every year the size of the annuity would be increasing by 19% and 16% for the stations situated in the first and second price areas correspondingly.

Due to a fact that the value of the average profitability of the government obligations changes every year a calculation of increasing annuity is carried out by the commercial operator in accordance with the equation:

$$r_i = \frac{R_i \cdot (k-1)}{k^{(16-i)} - 1}\,, \tag{2.5}$$

Where
k is equal to 1.19 for the suppliers located in the first price area and 1.16 for the suppliers located in the second price area.

Calculation of the capacity price component which provides return of capital and operating costs in year *i* is carried out by the commercial operator via equation:

$$P_{\substack{capital,\\ operat}\ i} = \frac{R_i \cdot ROR_{i-1}}{(1 - T_{profit})} + r_i + OC \cdot k_{spot}, \quad (2.6)$$

Where
Tax_{profit} is the profit tax rate equal to 20%;
OC is the standard value of operating costs stated for the year 2010 in the methodic

The value of $P_{\substack{capital,\\ operat}\ i}$ is formed from three components: the first component $\frac{R_i \cdot ROR_{i-1}}{(1 - T_{profit})}$ ensures profit earning (the reason why a profit tax T_{profit} is applied) with a stated interest rate, the second r_i component provides return on capital investments in form of annuities and the third component aims to refund operational costs of the stations.

Finally, the capacity price in the year *i* is calculated in accordance with equation:

$$P_{capacity} = (P_{\substack{capital\\ operat}\ i} + PT_{average} \cdot k_{spot}) \cdot k_{aux}, \quad (2.7)$$

Where
$PT_{average}$ is the monthly average property tax rate

Appendix 3

Cost estimation of the investment project

The total costs of the investment project are estimated as a sum of discounted payments for electricity and capacity and payments for the technological reserve formation divided by the volume of electricity produced during the contract's period:

$$TC = \frac{\sum_{j=1}^{n} \frac{(\sum_{i=1}^{3}(t_{ij} \times N_i \times T_{ij}^{Elect}) + RP_j + P_j^M \times N)}{(1+D)^j}}{N \times \sum_{j=1}^{n} t_j} \quad , \qquad (3.1)$$

where

t_{ij} is the forecasted number of hours of installed capacity usage for in year *j*, determined for the load mode *i* of the station

t_j is the forecasted duration of period during which station is used. This value is calculated via the formula:

$$t_j = \frac{\sum_{i=1}^{3} t_{ij} \times N_i}{N}, \qquad (3.2)$$

where

N is installed capacity of the generating object;

N_i is capacity of the station in the load mode *i*;

RP_j is the rate of the annual payment for the technological reserve formation in year *j*;

P_j^M is the value of payment for capacity submitted by an investor in his offer to the contest for year *j;*

D is the rate of discounting;

T_{ij}^{Elect} is the electricity tariff defined by the commission which is applied for the estimation of cost of electricity produced by the station in the mode *i* in year *j* of the contract. The tariff varies depending on the type of station.

Appendix 4

Preliminary results of the capacity auctions organized by the System Operator in August 2010 to select capacities for 2011 year

Table 4.1 Results of preliminary auction for 2011 in the first price area of the market (Opadchii 2010)

Area of free power flow	Selected, [MW]	Not selected, [MW]	Minimal price, [RUB/MW per month]	Price cap, [RUB/MW per month]	Highest price offer, [RUB/MW per month]
Ural*	24440	0	37425	118125	549899
Tumen	12703	0	37425	118125	900000
Northen Tumen	24	0	37425	118125	1548319
Serovo-Bogoslovsii area of Sverdlovski region	635	0	37425	118125	427747
Perm’	1352	0	37425	118125	578607
Vyatka	2017	0	37425	118125	153270
Volga	11666	0	37425	118125	489060
Kinderi	2328	0	37425	118125	148631
Balakovo	6603	0	37425	118125	454264
Kaukaz	1870	0	37425	118125	913507
Volgograd	3557	0	37425	118125	113836

Kaspii	490	0	37425	118125	79159
Rostov	4997	0	37425	118125	818753
Kuban’	3490	0	37425	118125	142915
Sochi	171	0	37425	118125	603640
Gelendgik	63	0	37425	118125	531630
Mahachkala	1416	0	37425	118125	234003
Centre*	33226	31	37425	118125	1394920
Vologda	664	0	37425	118125	232825
Moscow	15364	0	37425	118125	545801
West	13179	0	37425	118125	471020
Kolskaya	3245	239	37425	118125	69618
Total	143500	270			

* *Areas of free power flow without price caps*

Table 4.2 Results of preliminary auction for 2011 in the second price area of the market

Area of free power flow	Selected, [MW]	Not selected, [MW]	Minimal price, [RUB/MW per month]	Price cap, [RUB/MW per month]	Highest price offer, [RUB/MW per month]
Siberia	29202	0	52212	126368	1050000
South Kuzbass	1380	0	52212	126368	430000
Omsk	1476	0	52212	126368	207210
Chita	1359	0	52212	126368	264000
Buryatia	1247	0	52212	126368	200000
Altai	1310	0	52212	126368	590480
Hakasia	571	0	52212	126368	491398
Total	36545	0			

Appendix 5

Comparison of different scenarios under Capacity Delivery Agreement for a made-up station 200 MW

Table 5.1. Net present values of the project at the end of 15 years period and the payback periods under an agreement in different scenarios

Forecast alternative	CAPEX,[billion RUB]	NPV, [billion RUB]	Payback period, [years]
Optimistic	6.6236	1.6184	12.4
Optimistic (1 year startup delay)	6.6236	0.3627	14.4
Pessimistic (penalty and auction price years that is 10% lower than the price in an agreement)	6.6236	-2.888	>15
Pessimistic (penalty and auction price years that is 30% lower than the price in an agreement)	6.6236	-4.984	>15
Pessimistic (penalty and auction price years that is 50% lower than the price in an agreement)	6.6236	-7.079	>15
Realistic (Price in the auctions during the last 5 years is 10% lower than the price in an agreement)	6.6236	1.3029	12.6
Realistic (Price in the auctions during the last 5 years is 30% lower than the price in an agreement)	6.6236	0.6718	13.5
Realistic (Price in the auctions during the last 5 years is 50% lower than the price in an agreement)	6.6236	0.0407	14.8