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Structural and Design Issues in the Russian Electricity Reforms

A Policy Note

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Acknowledgment: This paper has been prepared primarily by Larry Ruff, independent consultant.

ACRONYMS

ATS	Administrator of the Trading System
CDU	Central Dispatch Unit
CHP	Combined Heat and Power (Plant)
CfD	Contract for Differences
DC	Distribution Company
FDS	Final Dispatch Schedule
FEC	former Federal Energy Commission. FTS now undertakes its functions.
FERC	U.S. Federal Energy Regulatory Commission
FGC	Federal Grid Company
FTRs	Financial Transmission Rights
FTS	Federal Tariff Service
GCC	Gas-fired Combined Cycle
GRF	Government of the Russian Federation
GS	Guaranteeing Supplier
HPP	Hydroelectric Power Plant
HWGC	Hydro Wholesale Generation Company
ICAP	Installed Capacity
IDC	Interregional Distribution Company
ISO	Independent System Operator
IT	Information Technology
ITC	Interregional Transmission Company
LMP	Locational Marginal Price
LRMC	Long-Run Marginal Cost
NPP	Nuclear Power Plant
PDS	Preliminary Dispatch Schedule
PJM	Regional transmission organization for several states of the USA, including Pennsylvania, New Jersey and Maryland (PJM)
RDU	Regional Dispatch Unit
RGC	Regional Generation Company
SCED	Security-Constrained Economic Dispatch
SO	System Operator
T&D	Transmission and Distribution
TGC	Territorial Generation Company
TPA	Third Party Access
TPP	Thermal Power Plant
TS	Trading Schedule
TWGC	Thermal Wholesale Generation Company
UDU	Uniform Dispatch Unit
UES	Unified Power System of Russia
WGC	Wholesale Generation Company

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1. INTRODUCTION AND SUMMARY

1.1 Context

Russia is engaged in a massive restructuring of its electricity system, with the objective of improving the economic efficiency of and attracting investment into the sector by creating largely privately-owned competitive generation and supply companies. This policy note provides an overview and critique of the industry structure and market design features of the reforms in the European and Urals regions of Russia; plans for the Far East and Siberia are less advanced and somewhat different, and are not discussed here. A separate policy note[1] discusses regulatory features of the Russian reforms.

1.2 Summary Conclusions

The Russian electricity reform program is undoubtedly the largest and most ambitious ever undertaken, both in terms of the size of the industry being restructured and in terms of the breadth and depth of the changes being made or planned. Other reform programs have gone from start to some target model in less time than is planned in Russia, where some reforms began in the mid-1990s and the target model will not be fully in place before 2008. But no other reform program has begun in such difficult circumstances or tried to change or create so many critical entities and processes for such a large system in one integrated effort.

The broad policy conclusions of the analysis in this paper are summarized as follows:

1. **The Target Structural and Market Model:** The basic organizational structures and market processes of the target model for Russia are consistent with – indeed, are explicitly based on – best international practice and are appropriate for Russia, i.e., disaggregation of vertically integrated entities into monopoly grid, system operations and spot market entities and competitive generation and supply entities, and creation of a central, integrated dispatch/spot market process based on locational marginal prices (LMPs) and financial transmission rights (FTRs). But the challenge is in the details and in the process for "getting from here to there", neither of which is yet fully defined for Russia and both of which may evolve along the way – as they have everywhere else. Thus, the critical issues for now concern the reform process,

[1] Policy Perspective and Analysis of Regulatory Regime in Restructured Russian Power Sector. June 2004.

and particularly the early steps that will shape what evolves later – and both the substance and the timing of some early steps raise some questions and concerns.

2. **The Reform Process:** The planned reform process is complex and will take a long time to complete, partly because any process for getting to the target model from where Russia is now will be complex and lengthy, but also because the plan sets some intermediate objectives that add to the complexity and length of the process. Some of these intermediate objectives should be reconsidered, because they may have too few benefits to justify the complexity and time they will add to the process. The principal intermediate objectives that should be reconsidered are:

   - *Retail Competition for Small Consumers*: The plan for the retail sector would allow/require retail competition for all consumers, even small ones, as soon as the wholesale market begins operating, scheduled for 2006-2008. Retail competition for small consumers has few benefits, creates large costs and risks, complicates many other features of the market and is not a realistic objective on this time frame in any case. The reform process would be greatly simplified and little would be lost if this objective were set aside for the time being, to be revisited in five or ten years.

   - *The Creation of Large Generation Companies*: The plan for generation – discussed in more detail later – is to spin off the generation assets of the now-vertically-integrated companies into new generation-only companies and then reorganize these into twenty-five to thirty large generation companies (3.5-9.0 GW each of various types (e.g., hydro, thermal, combined-heat-and power or CHP)) before selling their shares to portfolio investors – a two-step process that will take years to complete. The restructuring process could be simplified and accelerated, and the end result might even be improved, if smaller companies were sold sooner and directly to strategic investors. The arguments against this approach are that smaller companies would not be worth as much as larger companies and that industrialists/oligarchs might buy generation assets and use them to distort competition in electricity or other markets. But the relative value of small versus large companies should be tested in the market, and the threat that buyers will create anticompetitive industrial structures will arise quickly in any event and must be confronted by the anti-monopoly authorities.

   - *The Transitional 5-15 Market:* The "5-15 Market" – so-called because 5-to-15 percent of energy is to be traded in it – is supposed to provide a transition to the target LMP market but is so different from that target that at some point it will have to be replaced with an LMP market that will operate very differently and produce very different results; the experience and expectations produced by operating the 5-15 Market will be useless or misleading. The transition will be much smoother and ultimately even faster if the 5-15 Market is replaced with a version of the target LMP/FTR market and vesting contracts are used to protect consumers from volatile LMPs. Operations in and LMPs from the transitional market would then be essentially the same as they will be in the target market, and as vesting contract cover was reduced over time participants would be gradually exposed more to LMPs and would have increasing incentives to enter into commercial contracts.

3. **The Reform Schedule:** The schedule for the Russian reforms calls for most of the significant business restructuring and market implementation to be completed some time in 2006, with only some share swapping required after that to reach the target ownership levels by 2008. If this schedule is met with slippage of no more than (say) one year, Russia will have accomplished more, faster, than almost any other major electricity reform program has done. Perhaps this is possible in the Russian context, but those in charge of the reforms should closely watch progress against schedule and be prepared to adjust schedules and expectations if and when necessary.

2. OVERVIEW OF THE RUSSIAN REFORMS

This section outlines in a qualitative way the current structure and ownership arrangements, and the planned reforms, of the Russian electricity sector. The discussion here deals only with the European and Urals regions of Russia, ignoring Siberia and the Far East (where the reforms are less fully defined and will probably be very different in form and extent), and does not include all details even of the European and Urals regions. The objective is not to describe the Russian system or reform process in detail, but to provide background for the policy discussion that follows.

2.1 The Current Structure and Ownership Arrangements

The Russian electricity system is currently dominated at all levels by RAO UES, the joint stock company that has evolved from the centralized entity that planned and operated virtually the entire electricity system of the former Soviet Union. Over the past decade, the effort to make the electricity sector more businesslike and to introduce private capital into it has resulted in the creation of many companies with complex ownership in most parts of the sector. The situation as of early 2004 is outlined here.

2.1.1 RAO UES

The role and ownership of RAO UES have changed significantly over the past decade and will change even more as the reforms continue, until RAO UES ceases to exist in anything like its present form. As of early 2004, RAO UES:

- is owned about 51-52 percent by the Government of the Russian Federation (GRF), about 10 percent by the GRF-controlled gas monopoly Gazprom, and the rest by private investors;
- owns and operates, through its wholly-owned subsidiary Federal Grid Company (FGC), all of the high-voltage (220 kV and above) transmission grid that interconnects the entire country (except some 220 kV assets that are owned and operated by regional energos and will be transferred to FGC as part of the reforms);
- owns and operates, through a subsidiary System Operator (SO), the high-voltage scheduling and dispatch system – consisting of the central dispatch unit (CDU) and seven "uniform dispatch units" (UDUs) that manage interregional dispatch – and as part of the reforms will take over most of the regional dispatch units (RDUs) now owned and operated by energos);

- owns and operates, sometimes through subsidiaries that include private minority shareholders, a majority or at least a controlling interest in all the large "federal" thermal power plants (TPPs) and hydroelectric power plants (HPPs);
- owns directly a majority of or at least a controlling interest in all but four of the seventy-four regional energos (see below).

All the nuclear power plants (NPPs) are owned by Rosenergoatom, which is wholly owned by the GRF.

2.1.2 The Energos

The seventy-four regional energos are joint stock companies with complex and differing ownerships and mixes of functions. For seventy of the seventy-four, RAO UES owns a majority or at least controlling interest, with local governments and private investors owning the balance. RAO UES also owns twenty-one percent of Bashkirenergo and fourteen percent of Novosibirskenergo. Irkuskenergo and Tatenergo are fully independent of RAO.

The energos have a diverse mix of functions and assets, but a typical energo owns and controls within its region:

- some regional subtransmission (220 kV) and all the lower-voltage distribution systems;
- combined-heat-and-power plants (CHPs) that produce both electricity and steam or hot water for district heating for both industrial and commercial/residential uses;
- in some cases, TPPs that are not CHPs and middle-size and small hydro plants or cascades of such plants;
- the pipeline systems that distribute heat from the CHPs directly to some large industrial consumers or to the local distribution systems owned by the energo or municipalities;
- the electricity and heat supply functions (i.e., tariff management, metering, billing, etc.);
- some power sector service operations (e.g., power plant repair and maintenance); and
- in some cases, regional dispatch units (RDUs) that manage the energo's subtransmission, distribution and generation assets and the interchanges between the energo and the RAO UES system (until the RDUs are transferred to the SO during the reform process).

2.1.3 The Administrator of the Trading System (ATS)

An Administrator of the Trading System (ATS) was created in 2001 to administer spot trading, and is now operating the transitional "5-15" market discussed later in this policy note. The ATS was capitalized and is now owned in equal shares by twenty-eight legal entities, including RAO UES, generating companies in which RAO UES owns majority interests, and other companies including some large consumers; all of these founding entities want to assure that there is a market and have interests in how that market operates. The ATS has an advisory/oversight board consisting of four generator/suppliers, four consumers/sellers and four public representatives

(two from the Federal Energy Commission[2] (FEC) and two from the Duma); this board has some influence on technical matters, but most policy decisions are made at the General Meeting of the twenty-eight owners.

2.2 The Proposed Long-Run Target Model

The long-run structural objectives of the Russian electricity reforms and a process for getting there are described in the "5+5 Plan" – so-called because it took the five years from 1998 to 2003 to create the current structure from the initial one, and it is projected to take another five years, until 2008, to complete the process – issued by RAO UES in 2003. The long-run target model outlined in the 5+5 Plan is summarized in this section, and the process for getting there is summarized in the next section.[3]

The target model described in the 5+5 Plan is consistent with what might be called the "standard" model for creating effective and efficient competition in electricity. The principal features of this increasingly standard model are: competitive sectors for electricity generation and supply (defined as the sale or marketing of electricity); system-wide or regional regulated monopolies in transmission and distribution (T&D); a centralized, more-or-less integrated dispatch/spot market process separate from and independent of any participants in the competitive generation and supply sectors; and bilateral energy contracting based on financial contracts for differences (CfDs) that hedge the volatility of spot prices.[4] In more advanced versions of this model, the spot market is based on locational marginal prices (LMPs) that reflect transmission constraints (and perhaps marginal losses), with financial transmission rights (FTRs) available to hedge the risks of the volatile congestion prices defined by locational differences in LMPs.

This standard market model can operate with different mixes of public and private ownership of the various entities in it, but at least most new generation must be privately owned if wholesale competition is to mean anything, and there must be privately owned suppliers/marketers if retail

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[2] The GRF was considering and then making changes in the regulatory structure during the period when this Policy Note was being prepared, including eliminating (or at least changing the name of) the Federal Energy Commission. These changes may or may not have implications for the overall schedule of the restructuring, but do not appear to affect the basic substance of this Policy Note – although some references here to specific regulatory and administrative agencies may be out of date.

[3] In this policy note, all page number references are to pages in the English translation of the 5+5 Plan unless otherwise indicated.

[4] The basic alternative to this model for a competitive electricity market is a model based on third party access (TPA) to monopoly transmission services provided by an entity that may also be a large or even dominant generator/supplier, and bilateral contracting with penalties on real time imbalances between contract and physical positions. The TPA/bilateral contracting model is dominant in Europe, but has yet to demonstrate that it can support effective and efficient competition. The England and Wales market based on the New Electricity Trading Arrangements (NETA) is a hybrid, in which a transmission system owner/operator separate from generation and supply operates a centralized, bid-based "balancing mechanism" that is explicitly designed NOT to be an efficient spot market but to penalize real-time imbalances between contract and physical positions.

competition is a serious objective. In the version of this standard model described in the 5+5 Plan, the various sectors have the following principal characteristics:

2.2.1 High Voltage Transmission

The existing Federal Grid Company (FGC) will become an independent company that will eventually own and operate all high-voltage (220 kV and above) transmission facilities on the interconnected system, including those 220 kV assets that are now owned by energos; any such assets not (yet) owned by FGC will have to operate under contracts and procedures established by the FGC. The FGC may operate through the seven wholly-owned interregional transmission companies (ITCs) that will be created during the reform process to correspond to the seven operating regions now used by RAO UES. The GRF will eventually own at least 75 percent plus one share of FGC, the minimum necessary under Russian corporate law to give GRF control of corporate restructuring decisions.[5] According to the 5+5 Plan (p. 11), the GRF may decide to combine the FGC and the SO (discussed next) into a single corporate entity. The option of leaving the FGC free-standing but combining the SO and the ATS into an Independent System Operator (ISO) is also being considered.

2.2.2 System and Spot Market Operations

System and spot market operations will be independent of any market participants and closely coordinated with each other, but there is still some uncertainty regarding the ultimate organizational structure and ownership. The 5+5 Plan says that the existing System Operator (SO) will, just like the FGC, become an independent company with the GRF eventually owning 75 percent of the shares. But there are strong logical and institutional arguments for combining the system operation functions to be performed by the SO with the spot market functions to be performed by the ATS, creating an independent system/market operator similar to the ISOs in PJM, New York and New England and the independent market operator (IMO) in Ontario. Combining all three organizations – FGC, SO and ATS – into a single organization is also a possibility, but is not being actively considered. Whatever the details, such independent infrastructure entities raise important issues of governance that require further development in Russia.

2.2.3 Low Voltage Distribution

The low voltage (less than 220 kV) distribution assets will be transferred from the energos and will eventually be owned by no more than five operating interregional distribution companies (IDCs). The ownership of these companies will evolve in a complex way during the reorganization, but it is assumed that, once a regulatory regime that assures open access to T&D has been established, the GRF may consider privatizing its stakes in the IDCs. (p. 13)

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[5] This 75 percent requirement is intended to protect minority shareholders. The electricity legislation specifically exempts the energos from this super-majority requirement so that, starting in January 2005, RAO UES can make the corporate changes required for the reforms even though it owns less than 75 percent of most energos.

2.2.4 Electricity Generation

The generation sector will be competitive and, apart from the nuclear and major hydro units, eventually entirely privately owned. It is not possible to control or to predict the long-run structure of a privately owned generation sector, because assets will be bought and sold and traded in the market to accomplish the commercial objectives of the various parties. Some alternative ways of dealing with energo-owned power plants are still being considered. But the target structure described by RAO UES in the 5+5 Plan and subsequent documents has the following principal parts:

- **One GRF-Owned Nuclear Power Company:** All NPPs are owned by the GRF through Rosenergoatom and hence are outside the control of RAO UES. The current NPP ownership and structure are expected to remain in place.

- **Four GRF-Majority Hydro Wholesale Generation Companies (HWGCs):** The hydro power plants (HPPs) will be divided among four HWGCs, one of which is a large pumped storage plant located in the Central European part of Russia that owns most of the pumped storage assets in the country. For operational reasons the HPPs in each river cascade will be kept together in the same company. The GRF will own a majority share of each HWGC, presumably to assure that the cascade systems remain integrated and do not exploit their potential local market power, but also to capture the large rents that will be created when these fully-depreciated assets begin selling power at market prices rather than at their own accounting costs.[6]

- **Six Privately-Owned Thermal Wholesale Generation Companies (TWGCs):** The thermal power plants (TPPs) now owned by RAO UES, and eventually the large TPPs owned by some energos, will be put into six large TWGCs. Each TWGC will have about 9 GW of capacity, all old-style gas and coal steam plants – i.e., no combined-cycle plants – located in different parts of the country in order to reduce the local market power of each TWGC. A TWGC can be in the supply business, and can presumably be divided into smaller entities that can remain as such or can be rearranged into different large companies. The GRF will eventually sell all of its interest in the TWGCs.

- **Fourteen Privately-Owned Territorial Generation Companies (TGC) owning Combined Heat and Power Plants (CHPs):** The CHP plants now owned by the energos

[6] An alternative proposal apparently debated in the GRF was to create a single HWGC, with more than 20 GW installed generation capacity, instead of four. Such a company could become a vehicle for cross-regional re-distribution (e.g., from the European part of Russia to Siberia) of the rents created by the difference between the relatively low cost of hydro power (given the near-depreciated assets of the hydro plants) and the liberalized market prices of electricity in the European part. Presumably, some of these rents would be used to finance the construction of large (uncompleted) hydro plants in Siberia where such rents are not available since the Siberian electricity market is not liberalized and the prices are determined by the regulator on a cost basis. The future of this proposal remains uncertain.

will be reorganized into fourteen[7] privately-owned territorial generation companies (TGCs), each with 3.5-5 GW of electric capacity[8]. Some TGCs would also own heat transmission pipelines that transport heat from their CHPs to some large consumers and to local entities that distribute and sell heat to residential and other customers. However, some minority shareholders and investors are proposing supposedly easier and faster alternative restructuring plans that could lead to different transition paths and ultimate structures; these alternatives are discussed later in this note.

- **Independent Generation Companies:** The four energos not controlled by RAO UES are expected to transfer their generation assets to subsidiary generating companies, thereby satisfying the legal requirement to separate generation and network businesses by January 2005. Energos cannot be compelled to privatize their generation assets, although some may choose to do so.

2.2.5 Electricity Sector Services

The service functions now provided by energos to themselves – e.g., maintenance, repair and information technology (IT) services – will be spun off to independent, private and more-or-less competitive service companies. In some regions the specialized service companies would be essentially monopolies, so implementation of this objective may be delayed or reconsidered there.

2.2.6 Electricity Supply

All final consumers will be able to choose among competitive suppliers of electricity, some to be spun off from the energos during their reorganization and others to be established by independent entities such as TGCs. To insure electricity supply to all consumers, even those who have not chosen or cannot get a competitive supplier, or whose supplier has gone out of business, there will be a "guaranteeing supplier" (GS) for each region. The GS will supply any consumer at the wholesale market price plus a reasonable mark-up to cover its costs and risks.

During a transition period of three years after the proposed market launch in 2006-2008, "households and other socially important consumer groups" (p. 18) are to be protected from the risks of wholesale price variations.[9] To provide this protection, GSs will have "vesting"

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[7] The 5+5 Plan refers (p. 35) to "about twenty" TGCs, but the latest plan from RAO-UES calls for fourteen: the group of 14 TGCs does not include generation from the Far East (possibly, another 6 TGCs or so), where the composition of generation as well as the overall restructuring plan are still not clear.

[8] Figures "3.5 - 5GW" are the most frequently cited. More precisely, some TGCs will go beyond this range. The ones based on the generation assets of Mosenergo and Lenenergo are among the bigger ones, some others are smaller. The interval of 2.5 - 7 GW would accommodate all TGCs, except the one based on Mosenergo's generation assets.

[9] Contracts to protect consumers and reduce uncertainty during the restructuring process before market launch would be very useful, given the uncertainties about both the effects and the length of this

contracts with wholesale suppliers for enough electricity to cover the demand of these groups, at prices adequate to "ensure a certain level of profitability" for the wholesale suppliers. The GSs will supply electricity to the socially important groups at the contract prices plus a reasonable margin.

It is unclear which entities will be, or will be allowed to be, a GS. Although the 5+5 Plan says (p. 14) that a GS "is a regulated business" that, "in contrast to the competitive sales [business], …can be combined with the distribution business," and the Electricity Law does not rule out this possibility, doubts have been expressed that a distribution business should (or could) be a GS. The 5+5 Plan also says (p. 15) that reorganization of energos will create "competitive supply companies" that "will perform the functions of GSs, unless otherwise decided by the state."

Just how the electricity (and heat) supply business will be structured and will operate in the target model is unclear. The feasibility and desirability of competitive electricity supply for small consumers are unclear, and there is uncertainty about the identity, role and regulation of GSs. A careful study of the legislation and policy documents might provide answers to some of the factual questions, but in general it appears that the many difficult issues in supply, particularly competitive supply for small consumers, have not been fully thought through in Russia.

2.2.7 District Heat Supply

Most energos appear to be accepting the RAO UES recommendation that the distribution and supply of district heat to final consumers be the responsibility of the TGCs that will own the CHP plants that produce heat along with electricity. In a few cases, the heat distribution pipelines themselves will be put into separate entities owned jointly by the TGCs, energos and municipalities.

2.2.8 The Wholesale Electricity Market

The centralized wholesale market to be operated by the ATS (or by a successor organization, perhaps one that combines the ATS and SO functions) has not been defined in detail, but is intended to be modeled closely on successful markets in the United States, primarily PJM. The plan is to use a bid-based, security-constrained economic dispatch (SCED) process to determine simultaneously a least-cost dispatch of the entire system and the associated LMPs, with FTRs to hedge congestion cost risks. There will be both a day-ahead market and a real-time balancing market. Contracts among generators, traders/middlemen and suppliers will be primarily financial CfDs, although some industrial interests want "physical" contracts that supposedly assure the contract buyer that its physical electricity will come from "its" contracted power plant(s); the issue of physical contracts is discussed in a later section of this Policy Note.

There is a strong feeling, particularly among generator interests, that a spot market and the short-term (e.g., less than a year or two) commercial contracts typically stimulated by such a spot market will not induce investors to build new generating capacity or even pay much for existing capacity. Even adding the type of short-term (e.g., monthly or seasonal) capacity obligations or

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process. But there is no provision in the law for such contracts, and no easy way to create them without a legal requirement.

payments used in some US markets will not help much, because the resulting stream of capacity payments are unpredictable. In this view, spot trading and short-term commercial contracts should be supplemented with long-term capacity payments or contracts provided by a stable and deep-pocketed entity such as the GRF or the SO. The 5+5 Plan does refer to the possibility of a "medium term" "capacity market (or capacity charge)" that might be added if and when needed to stimulate investment, but does not appear to recognize the profound implications of such an addition. The issue of capacity payments is discussed in a later section of this Policy Note.

2.3 The Process for Getting There

The "standard" structure and market processes just described are reasonable as long-term targets even for Russia, but are worlds away from what exists in Russia today. To create the target structure, the vertically integrated monopolies – RAO UES and the energos it controls in the European and Urals regions must be disaggregated into their functional pieces and then reassembled into fewer, horizontally integrated companies. To create the target market processes, the old central dispatch process, which was (and largely still is) based on rigid priorities and physical targets and quotas, must be replaced with an integrated dispatch/spot market process.

The details of the restructuring process in each of the principal sectors are discussed in turn below. The typical process for each horizontal sector – i.e., transmission, generation, distribution – includes the following steps (simplified for discussion purposes by assuming that only one horizontally integrated company is to be created):

- Each of the vertically integrated entities will establish an operating subsidiary to which it will assign the assets to be transferred into the horizontally integrated entity, and will then spin off that subsidiary as a separate operating company with shareholdings that mirror those of the parent. Because RAO UES currently owns or has a majority interest in the SO, FGC, the federal power plants and (almost) all energos, RAO UES will have a majority interest in each of the spun–off operating companies. Where RAO UES will own 75+ percent of these first-stage operating companies, it can simply merge them into the larger operating companies desired in the target model, paying off minority shareholders with shares in the large companies.
- Where RAO UES will not own 75+ percent of the first-stage operating companies, RAO UES will establish a wholly-owned holding company, assign its shares in each of the newly created operating companies to the holding company, and invite minority shareholders to do the same in exchange for shares of the holding company at exchange ratios based on analytical valuations and negotiations. As minority shareholders take up these offers – which may require RAO UES to offer attractive exchange ratios that, in effect, pay premiums for minority shares – the RAO UES interest in the holding company will be diluted.
- If and when the holding company has enough shares in the operating companies, it can buy out the remaining minority-held shares in exchange for holding company shares, so that the operating companies becomes wholly-owned subsidiaries of the holding company. The operating companies can then be combined into a single, integrated operating company owned by RAO UES and others.

- The GRF will now own a share of the single-share operating company equal to its share in RAO UES multiplied by RAO UES' now-diluted share in the single-share company (plus the shares held by any other GRF-controlled entity, such as Gazprom). In order to reach the GRF's share targets – e.g., 75+ percent of the infrastructure companies, 52+ percent of the hydro WGCs, zero for the thermal WGCs – RAO UES can exchange shares in one entity for shares in another, or can buy and sell shares for cash, e.g., can sell shares in generating companies and buy shares in the transmission company.

- At some point, now scheduled for about 2006, the energos and RAO UES will go out of existence in their current form, and their share holdings in the various operating companies will be distributed among their shareholders pro rata. The new, horizontally integrated companies will now be owned directly by the entities that previously owned the vertically integrated companies – i.e., the GRF, Gazprom, private investors, etc. – and by anybody who bought shares in the market during the process.

This process is very complex and time-consuming, and at several points requires the exchange of shares in different entities that cannot be easily valued, virtually guaranteeing conflict and strategic behavior. Minority shareholders can slow or block the process at various points if they do not think they are getting fair value, or simply because they think they can get a better deal by holding out. There are many things that can go wrong and no guarantee of success. But the GRF and RAO UES management are committed to the restructuring, and minority shareholders generally support it because they think that, if done well, it should create significant shareholder value in which they will share. This could eventually bring the desired results. The process for each sector is described more fully below.

2.3.1 High Voltage Transmission

Creating new corporate entities to carry on the monopoly infrastructure functions now in RAO UES is relatively straightforward and is already largely accomplished. The GRF owns a majority of RAO UES shares and hence could – and did – direct RAO UES to create a wholly-owned subsidiary corporation (FGC) to take over RAO UES' high voltage transmission and another (the SO) to take over the central system operation function and assets.

Some energos now own 220 kV assets that in the target model are to be owned by FGC. To obtain these assets, FGC will create seven wholly-owned Interregional Transmission Companies (ITCs) that initially have essentially no assets, and then RAO UES will use its controlling interest in energos (and the fact that electricity law exempts energos from the seventy-five percent rule) to transfer the 220 kV assets of each energo into one of the ITCs in exchange for ITC shares at some exchange rate reflecting the relative value of each energo's 220 kV assets. This will result in energos rather than FGC owning most of the ITC shares. [10]

FGC will then try to buy the energos' ITC shares at "the market price," using money it raises either by borrowing in the capital markets or from the GRF, or by selling more equity shares to the GRF (at some price). If FGC is unable to buy the ITC shares from the energos before the

[10] The FGC could transfer its regional 220 kV assets into the ITCs, so that it would start with a larger stake in each ITCs, but this does not appear to be the plan.

energos are reorganized – presumably because of minority shareholder opposition[11] – each energo will distribute its ITC shares among its shareholders on a pro rata basis. RAO UES will then hold the majority of ITC shares, which it will transfer to FGC in exchange for FGC shares. Minority shareholders in the ITCs will be encouraged to exchange their ITC shares for FGC shares at some ratio, and then the GRF will attempt to increase its share in FGC to the target of 75+ percent, using "all lawful means …, including through sale or exchange of the government's stake in GenCos." (p. 11) The ITCs may either continue as separate operating companies controlled by FGC or be absorbed into a single FGC operating company.

Many steps in this process – the transfer of energo 220 kV assets into the ITCs, the purchase by FGC of the ITC shares, the exchange of ITC shares for FGC shares and the purchase of FGC shares by the GRF – require valuation of complex assets and/or operating entities. But in Russia there are no markets in which such values can be estimated, and in any case the value of a regulated infrastructure entity such as FGC and the ITCs depends largely on regulatory policies that are not yet defined.[12] It is no surprise that minority shareholders are cautious about this process or that the 5+5 Plan says (p. 11): "The complexity of … this issue necessitates its further study and detailed review."

2.3.2 System Operations

The SO has been created as a wholly-owned RAO UES subsidiary that now owns and operates the central dispatch unit (CDU) and seven uniform dispatch units (UDUs). The energo-owned regional dispatch units (RDUs) are to be transferred to the SO in exchange for SO shares. At some point the SO will be spun off as a separate company with shareholdings mirroring those of RAO UES, and the GRF will have to acquire SO shares in order to reach the targeted 75+ percent share of the SO ownership. These processes will raise valuation issues similar to those just outlined for the FGC, but the problems should be less serious because system control assets are much less costly and diverse than transmission assets.

2.3.3 Electricity Distribution

Each energo will put its electricity distribution assets into a distribution company (DC) with shareholdings that mirror those of the energo, giving RAO UES a majority share in (almost) all DCs. RAO UES will create up to five wholly owned holding companies called interregional distribution companies (IDCs) and will then transfer its DC holdings to the IDCs. Minority shareholders in the DCs will be invited to exchange their DC shares for IDC shares (at some

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[11] Because RAO UES owns a controlling interest in energos, it should be able to "persuade" the energos to sell. But because RAO UES also owns 100 percent of FGC, it has an inherent conflict of interest, i.e., if energos sell their assets to FGC too cheaply, RAO UES (and hence the GRF) will gain at the expense of minority energo shareholders. Minority energo shareholders are naturally cautious or even outright suspicious of the plan to sell energo assets to FGC, and may have enough legal and political leverage to make this difficult.

[12] The fact that market values depend on regulatory policies can help solve the problem of valuing the various infrastructure entities. For example, the GRF could assign some "reasonable" market value to each infrastructure entity during the reorganization and then direct regulators to allow each such entity to earn a market rate of return on its book value, defined initially as the market value assigned by the government. It is not clear that such an approach is understood or contemplated in Russia.

exchange ratios), so that ultimately all shareholders will hold only IDC shares and the DCs will be wholly owned subsidiaries of the IDCs. Again, serious issues of valuation and protection of minority shareholders will arise in this process.

According to the 5+5 Plan (p. 12), "[a]s a result of such exchange[s], the share of RAO UES … in IDCs may fall to a level not less than 49%."[13] During the reorganization of RAO UES in 2006, another holding company of which the GRF will ultimately own at least 52 percent will be created to hold all of RAO UES' IDC shares. After completion of the reorganization of RAO UES and the establishment of a regulatory regime assuring non-discriminatory access to transmission and distribution facilities, the GRF may privatize distribution by selling its stakes in the IDCs.

2.3.4 Electricity Generation

It is the restructuring of generation that is attracting the most attention and concern in Russia, presumably because generation is the most interesting for investors and the most important for competition. The reorganization processes described in the 5+5 Plan for the different parts of the generation sector are summarized here.

- **Hydro Wholesale Generation Companies (HWGCs):** The four HWGCs will be relatively easy to create, because the hydro plants that will go into them are now wholly owned by RAO UES. RAO UES will establish four wholly-owned subsidiary HWGC holding companies and transfer to each of them the designated HPP plants/cascades. These subsidiaries will then be established as independent "production-financial holdings," with share holdings identical to the capital structure of RAO UES. The HWGCs may sell shares to non-GRF entities, subject to the GRF's stake remaining more than 50 percent. Sale of these HWGC shares will help pay for the GRF's purchases of FGC, ITC and SO shares.

- **Thermal Wholesale Generation Companies (TWGCs):** The six TWGCs will be somewhat harder to create than the HWGCs, because some TPPs already have minority shareholders and others are owned by energos. But the basic process is the same: RAO UES will establish (or has already established) subsidiary companies for each TPP and six wholly-owned TWGC subsidiaries; RAO UES will transfer its shares in each TPP to the designated TWGC and invite minority shareholders and energos to do the same in exchange for TWGC shares; if and when a TWGC holds enough of the TPP shares, it may buy out the remaining minority shareholders to create a single-share, integrated operating company. The difficult and contentious part of all this is, obviously, the valuation of the various shares that are being exchanged; RAO UES has contracted with Deloitte & Touche to develop a uniform business procedure for these valuations. The GRF will eventually sell its entire stake in the TWGCs, using the proceeds to help pay for its purchases of FGC, ITC and SO shares.

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[13] The significance the 49 percent limit is unclear; 51 percent would make more sense. RAO UES will start with more than 50 percent of the energos and hence of the initial DCs, so its share in the IDCs should not fall below 50 percent unless it pays premium prices (in IDC shares) for minority DC shares.

- **Territorial Generation Companies (TGCs):** Creation of the TGCs will be the most difficult and uncertain part of restructuring generation, both because of the inherent complexity of the CHP assets and systems and because of the restructuring process chosen by the GRF and/or RAO UES. The restructuring process described in the 5+5 Plan is broadly the one outlined above: each energo of the roughly fifty-five energos that has CHP assets will spin them off into one or more operating companies called regional generation companies (RGCs), each with shareholdings mirroring those of the parent energo; RAO UES will create (at latest count) fourteen holding company TGCs and then transfer to each TGC the RAO UES shares in the RGCs designated for that TGC; minority shareholders in RGCs will be invited to exchange their RGC shares for shares in the designated TGC; when each TGC has enough RGC shares it will be converted into a single-share company. Each TGC will then either combine its RGC operations to form an integrated operating company or reorganize its RGCs into larger RGCs and remain a holding company for these.[14]

  The general restructuring process – based on spinning off assets into operating companies that are then transferred to holding companies that are then converted into single-share operating companies – may be reasonable when it is easy to create the first operating companies, e.g., when RAO UES spins off each of its thermal power plants or hydro cascades into a single operating company. But the CHP plants are parts of complex, integrated, politically sensitive energos; they provide not only electricity but commercial and residential heat (which is politically very sensitive in a very cold climate with many poor people), employ thousands of people and are subject to complex regulation. Creating each RGC will require identifying and transferring the appropriate assets and staff and creating and funding balance sheets. Executive management and governing boards must be created and educated about the new companies so that they can make informed decisions about further share exchanges and restructuring. Only then can the value of each RGC be estimated/negotiated so that RGC shares can be traded for TGC shares to create the single-share TGCs. And then the operating RGCs will have to be restructured again to create the larger operating companies that are the ultimate objective.

  The difficulties and delays inherent in the 5+5 Plan's approach to creating operating TGCs have led some minority shareholders and investors to suggest alternative approaches based on skipping the operating RGC step and going directly to TGCs. Although the several alternatives differ in details, the essence of them all is that each energo would transfer its CHP assets directly to a TGC in exchange for TGC shares and then distribute the TGC shares among its shareholders in proportion to their energo shares. RAO UES, as majority shareholder in the energos, would get a majority of the shares in each TGC, which it could exchange, directly or though cash sales and purchases, for shares in the infrastructure companies. This would presumably allow a relatively rapid transfer of generation assets to private investors and of infrastructure assets to the GRF.

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[14] The possibility that RGCs might be merged in to larger RGCs under a holding company TGCs is suggested by the 5+5 Plan, which says (p. 14) that RAO UES "is willing to support such [merger] activities." There is not much point in merging RGCs unless the merged RGC is to remain an operating company under a holding TGC (or is to be spun off into a separate operating TGC).

Skipping the RGC step and going directly to multi-energo TGCs would not eliminate the need to identify and transfer CHP assets and staff from each energo and would add the need to value each energo's CHP assets before the first step in the process could proceed; it would probably take longer to create the TGC directly than to create the RGCs as an interim step to the TGCs. But going directly to TGCs would mean that only about twenty rather than fifty-five operating companies would have to be established in the first step, and once established these companies would not have to be restructured again before being sold to private investors. So skipping the RGC step would probably move forward full privatization of the TGCs – and of the day when private owners could begin breaking up the TGCs and rearranging the pieces for their own purposes, whether this is good or bad from a public policy perspective. A process in which energos sell their CHP assets directly to the TGCs might also make it more likely that a strategic investor would make an energo a better offer and buy some CHP generating plants.

At the time this Policy Note was being finished (i.e., early May 2004), the RAO UES Board of Directors was reported to be considering a proposal from management to accelerate the creation of operating TGCs. Under this proposal, TGCs would be created before or in parallel with separation of generation assets from energos, and would take over management of some generation assets under lease arrangements. The rest of the process would continue as planned, i.e., ownership of generation assets would be separated from energos, consolidated into RGCs and then further consolidated into the corresponding TGCs, even while some of these assets are being operated by TGCs. This would make the TGCs operating companies earlier in the process, but would not change the target ownership of the TGCs.

2.3.5 Electricity Supply

The 5+5 Plan says (p. 15) that reorganization of the energos will "entail the incorporation of competitive supply companies" that will "perform the function of GSs [guaranteeing suppliers] (unless otherwise decided by the state)" and may be part of the local distribution company. Other suppliers unaffiliated with the energo are expected to appear more or less spontaneously. If the GRF grants GS status to a supplier other than the energo affiliate, the energo affiliate will become a competitive supplier.

The 5+5 Plan suggests that all consumers, even small ones, will have the option of buying from a competitive retail supplier from the start of the wholesale market, but gives no rationale or reason why this is realistic, or desirable, or necessary. A GS must offer to supply residential and other socially important consumers at prices that, for a three year transition period, will be determined primarily by vesting contracts that will be imposed on generators during the restructuring process.

2.3.6 The Transitional 5-15 Market

While the various corporate entities are being reorganized and created, the ATS will be operating a transitional process called the "5-15 Market" – because it uses market-like procedures and terminology and something between 5 and 15 percent of electricity is expected to be traded in it. Presumably, the purpose of this process is to give system operators and prospective market participants experience with and confidence in electricity markets, and to begin producing prices

indicating what should be expected once the full LMP market begins operating. The 5-15 Market began operating in a partial way on 1 November 2003 and fully on 1 January 2004 – although only a small fraction of energy is actually traded in the market.

As detailed in a separate background paper,[15] the 5-15 Market is not a market in a real sense, but a complicated and not fully logical set of scheduling/dispatch and payment arrangements. In brief, the 5-15 Market is a day-ahead market/process that operates roughly as follows:

- Each day, all (wholesale) demands submit to the SO "bids" for energy for each hour of the following day – actually, expected demands with no associated prices – and the SO prepares a Preliminary Dispatch Schedule (PDS) for generation over the next day. The PDS is based on the SO's established generation scheduling process, and hence is presumably a generation schedule that meets actually expected demand within the SO's reliability criteria.[16] The SO sends the PDS to the ATS, along with information on the status of the transmission system, hydro generation, required reserves, etc.
- For those demands and generators who choose[17] to participate in the 5-15 Market, the ATS reduces the PDS quantities by 30 percent for demands and 15 percent for generators, and these reduced quantities become the base quantities in the 5-15 Market, i.e., these reduced quantities will be bought and sold at regulated prices. The ATS accepts market bids from demands and generators indicating the incremental quantities above the reduced PDS quantities that each demand is willing to buy in the 5-15 Market at different prices and each generator is willing to sell at different prices.
- The ATS performs two security-constrained economic dispatch (SCED) runs, using each the same full nodal model of the transmission system. In the first of these SCED runs – called "Problem P" – demands are fixed at the full PDS quantities that represent actual expected demands, and the market offers and regulated prices of generators are used to determine a day-ahead Trading Schedule (TS) – i.e., a dispatch of generation – by minimizing a highly artificial measure[18] of the total generation cost of meeting these demands.

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[15] Sorokin, Igor, "Outlines Of The Electric Energy (Power) Wholesale Market Arrangements For The Transition Period."

[16] The SO's scheduling and dispatch process at this stage appears to be largely a hold-over from the old system of physical quotas and targets. It is based on a system of generation priorities among nuclear plants, plants that must run to stabilize the transmission system, run-of-river hydro plants and CHP plants that must run to produce heat, along with monthly energy output (or fuel consumption) targets for each thermal generator.

[17] Although participation in the 5-15 Market is voluntary, all generators have had their capacity payments reduced by 15 percent, on the theory that energy prices in the 5-15 Market would be high enough to cover both energy and capacity costs, i.e., generators do not have the option of remaining fully under regulated prices, and hence are economically compelled to participate.

[18] The cost function to be minimized measures the cost of 5-15 Market output at its offer price, but measures the cost of regulated output at its regulated prices *multiplied by a factor of ten*. This virtually guarantees that all market-price offers will be scheduled before any regulated-price offers (although this would probably happen anyway, given that regulated prices include capacity cost

- The ATS sends the TS to the SO, who determines whether it meets system reliability criteria; if it does not, the SO modifies it to produce the Final Dispatch Schedule (FDS) that, in effect, defines the planned actual operations of the system to meet actual expected demands while satisfying the SO's reliability criteria. Given that the Problem P solved by the ATS begins with the PDS from the SO and includes the same system constraints used by the SO, there should not be much difference between the SO's FDS and the ATS' TS.
- In the second SCED run – called "Problem K" – the ATS reduces PDS quantities by 30 percent for both demand and generation and then finds a dispatch that maximizes the "gains from trade" or "social welfare" based on the bids and offers in the 5-15 Market, subject to the various constraints limiting how much can or must be traded at different prices, e.g., no generator may sell more than 15 percent of its PDS quantities in the 5-15 Market or less than 85 percent of its PDS quantities at regulated prices, total demand purchased in the 5-15 Market cannot exceed 15 percent of total PDS quantities, etc. The LMPs and 5-15 Market quantities arising from this artificially constrained problem are used for settlement in the 5-15 Market.
- If the 5-15 Market were a real market, each demand would be expected to consume only the quantity it purchased in that market plus the 70 percent of PDS quantities it was entitled to consume at regulated prices, and would pay high real-time balancing prices or imbalance penalties for any consumption above that. But in the 5-15 Market, buyers know that, no matter how much or how little they buy in the market, they can take the full quantities they initially "bid" to the SO – indeed, they must do so or pay imbalance penalties – and pay regulated prices for the amounts they take in excess of their market-determined quantities. So in real time, actual demand is (approximately) what was projected by the SO at the day-ahead stage, and generation must be dispatched to meet this actual demand, even if little demand or generation cleared in the 5-15 Market.
- In the end, the combination of the PDS and FDS, the 5-15 Market solution, adjustments needed to meet actual demand in real time and (not discussed above) bilateral contracts of several types determine a specific amount of energy that each demand and generator should consume or produce in each hour in real time. Differences or imbalances between these quantities and real-time operations that exceed tolerance bands of ±5 percent for buyers and ±3 percent for sellers result in imbalance payments that are determined by formulas and depend on regulated prices, whether the imbalance was positive or negative, and whether it was or was not in response to instructions from the SO.

As compared with modern electricity markets functioning elsewhere, the most obvious problem with the 5-15 Market is that it is not a true market, but a complex and largely ad hoc process for determining dispatch and payments. In Russia, however, the most frequently-cited problem with the 5-15 Market is that it has an inherent tendency to produce prices that are far too low. Because consumers will automatically buy at regulated prices whatever they do not buy in the 5-15 Market in each hour, they have no incentive to bid more than the regulated price. But generators cannot produce more than 85 percent of their SO quantities unless they sell in the

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recovery), results in a dispatch that must often be inefficient and meaningless LMPs (which are not used for anything and may not even be explicitly computed).

market, so they have strong incentives to compete with one another for incremental sales by offering low prices. The result is that prices in the 5-15 Market are consistently and significantly below regulated energy prices – which are themselves usually below the long-run marginal cost (LRMC) of supplying electricity. Given that Russia has a lot of excess capacity, prices below LRMC are not in themselves a sign that the market is working poorly; but given the logic of the 5-15 Market, even if Russia had an optimal amount and mix of capacity, prices in the 5-15 Market would be significantly less than LRMC.

Although the most obvious problem with the 5-15 Market is the too-low prices it produces, there are other, less obvious problems that may be just as serious. These problems and their implications are discussed further in a later section.

3. ISSUES AND RISKS IN THE RUSSIAN ELECTRICITY REFORMS

It is not the intent of this report to offer a detailed critique of or detailed recommendations concerning the electricity reforms planned for Russia. But it may be helpful to point out features of the proposed Russian reforms that raise important policy issues or have the potential to create serious problems if not handled properly. This section discusses such features and their implications, and suggests some alternative approaches or at least offers some warnings. It begins with the target model, moves to the restructuring process and ends with the trading and contract arrangements.

3.1 The Target Structure

The target model outlined in the 5+5 Plan is consistent with the increasingly standard model of a competitive electricity market. This model is appropriate for Russia as a general matter, but the details must be consistent with the particular characteristics of Russia. And even the standard model, while generally successful, has some weaknesses that should be recognized more than they may be in Russia. This section discusses some features of the target model that may be problematic for Russia even if they work well elsewhere, and other features that have not worked very well elsewhere and are unlikely to do any better in Russia.

3.1.1 The Structure and Role of the Grid Company

A single grid-owning company for the entire nation is consistent with the standard model, but is not necessary. In a country as large as Russia, there could be several regional grid companies, each beginning as a regional monopoly but competing with other grid companies to provide certain services and even new transmission projects, particularly on the boundaries between regions. Such incremental competition among grid companies can give consumers and grid planners better information and more options.

State ownership of the grid company – or even of several grid companies – is also consistent with the standard model but is also not necessary or, in many cases, desirable. Properly regulated private monopolies generally outperform state-owned monopolies, because they can have stronger performance incentives, more flexibility in staffing, and more ability to resist political interference in staffing and investment decisions. But strong regulatory institutions are necessary to regulate a grid monopoly properly, so in Russia state ownership of the critical

infrastructure monopolies may be the best solution until adequate regulatory institutions are in place.

The biggest questions related to the grid company – FGC in Russia – are also the biggest unanswered questions facing electricity markets everywhere: how to decide when and where to build new transmission capacity and who should pay for it. The hope that "the market" would somehow answer these questions by giving market participants incentives to identify transmission options, choose among them and then willingly pay for the chosen options has proven to be unrealistic. LMPs and FTRs can provide some of the information and incentives needed to guide and motivate transmission investments, but in the end a centralized planning and regulatory process is needed. Russia may not need much grid investment for a while, but eventually it will have to develop mechanisms for planning, choosing and paying for grid investments.

It is understandable that the 5+5 Plan says nothing about grid planning and investment, given that it is a corporate plan for restructuring RAO UES assets, not a policy statement for the entire system. But it is less understandable and far more serious that there is nothing in the Electricity Law or GRF policy statements about transmission planning and investment. The implicit assumption seems to be that FGC will decide when to build which transmission projects, will build and own itself all the transmission it decides is needed, and will recover its costs through tariffs of some sort. Such a unilateral process works reasonably well in an integrated monopoly, but is inappropriate or even infeasible in a market-based electricity system. Deciding what to build and who should pay for it requires a joint process involving the system operator, market participants, the regulator(s) and the grid owner. The grid owner must help identify and analyze transmission options, and will probably – but not necessarily – build, own and operate the chosen options. But the grid owner cannot do this all itself, may not even be the appropriate entity to lead the process, and should certainly not be the final decision maker, i.e., FGC cannot have the power to decide for itself what it will build and to compel somebody else to pay for it.

3.1.2 The System Operator and Spot Market Administrator

The 5+5 Plan says that the SO will be an independent company regulated by the appropriate governmental agencies, but says nothing else about how the SO will be governed or how it will make its decisions. Again, it is understandable that a RAO UES corporate planning document says nothing about such matters, but it is a source of serious concern that the Electricity Law and GRF policy statements are also silent on the question of how critical infrastructure monopolies will be governed and regulated, or how system-wide decisions will be made. The assumption implicit in the 5+5 Plan is that the SO, like the FGC, will be an ordinary company governed by a shareholder board with the objective of maximizing shareholder value subject to regulatory constraints. This is not an appropriate, or at least is not the usual, way an independent system operator is organized and governed. At the least, there should be a separate policy board whose objective is to assure that the system operates reliably and efficiently, not just to maximize shareholder value.

The future ATS is barely mentioned in the 5+5 Plan because it is not now part of RAO UES, so it is even less well-defined than the SO. The implicit assumption is that the future ATS will be or will evolve from the current ATS, which is owned by twenty-eight market participants and has

an oversight board with less-than-optimal membership and unclear authority. Some better governance arrangements will be needed.

The key questions regarding the SO and the ATS are whether they should be combined into a single independent system-and-market operator and how they should interact with each other if they remain separate entities. The logical and practical arguments for combining them into a single Independent System Operator (ISO) are persuasive, particularly given that it has already been decided that an integrated SCED process will be used to determine the physical dispatch and the market's settlement LMPs simultaneously. Either the SO should absorb the ATS' spot market functions and become an ISO – perhaps leaving the ATS as a separate organization that processes bids and settlements, trades derivatives, etc., – or a new ISO entity should be created to combine all the SO and ATS functions. Either way, there should be a policy board with the objective of assuring that system operations are reliable and that the market works well, not just maximizing shareholder value.

3.1.3 The Size and Composition of Generation Companies

The target structure for the generation sector consists of relatively few large companies. Indeed, an explicit objective of the restructuring is "maximum possible consolidation of the established companies combined with ensuring efficiency for the business and shareholders and prevention of monopoly/oligopoly." (p. 21 and, with slightly different wording, p. 40). In other words, the objective is maximum company size subject to efficiency and competitive constraints, not maximum efficiency and/or competition subject to some minimum company size constraint. This section discusses whether it is necessary or wise to make maximum company size the primary objective.

It is reasonable to have only one large nuclear power company, given the need for specialized skills and tight control of NPPs and the fact that NPPs are largely price-takers that have little potential market power. It may also be reasonable to have a few hydro wholesale generating companies (HWGCs) controlled by the GRF, given the perceived need to keep river cascades within a single company and to control the environmental and other effects of hydro production (although government ownership does not guarantee operation in the public interest). But the target model has only six thermal wholesale generating companies (TWGCs), each with about 9 GW of capacity, and fourteen territorial generating companies (TGCs), each with 3.5-to-5 GW of CHP capacity. These companies would not be particularly large compared to the largest generation companies in the world, but probably larger than necessary to capture scale economies and large enough to be difficult to sell to strategic investors and to create potential market power problems even if defined with market power concerns in mind (as they have been[19]).

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[19] Detailed modeling of a specific market can demonstrate that some generation structures ***will*** create market power problems but can seldom demonstrate conclusively that some structures ***will not*** create market power problems. Local market power created by transmission constraints can be a problem even with small or single-plant companies, but multi-plant companies can have many subtle ways to manipulate transmission congestion.

The 5+5 Plan says that the principal reason for creating generating companies as large as possible subject to efficiency and competitive constraints is that potential partners, customers and particularly portfolio investors want large, financially stable companies. Unofficial sources suggest that the GRF and/or RAO UES have other reasons for wanting a few, large companies, including a fear that smaller companies would be purchased by strategic investors or oligarchs whose objectives may be inconsistent with creating an efficient and competitive wholesale market, and a desire to create large Russian companies who can operate successfully in world markets as "national champions." It is noteworthy that attracting strategic investors, either foreign or domestic, does not appear to be a major objective.

The argument that Russian generation companies should be large so that they can operate successfully in world markets is weak; newly privatized generation companies that have plunged into the highly competitive international generation game have almost invariably lost a lot of money. The other arguments for creating large generation companies during the restructuring process boil down to a belief that current GRF officials and RAO UES management are better than the market at deciding how generation assets should be grouped to create successful companies, so they should define and put in place a target structure that will be hard to change.

Portfolio investors, many of whom are or represent[20] foreigners, have helped drive up the price of RAO UES shares as RAO UES has become more stable and apparently[21] profitable over the past decade. Such investors prefer large, stable, even monopolistic companies, because these are relatively easy for outsiders to value and monitor and have shares that are relatively liquid. Portfolio investors, especially if there are many of them and each owns only a small piece of the company, are also unlikely to mount a successful effort to change a company's management, policies or structure. It is understandable that RAO UES management wants to create the kind of large companies that will be attractive to such investors.

The strategic investors in electricity are now primarily large Russian industrial companies who want to gain control of electricity assets for their own commercial reasons. For example, fuel producers may want to assure markets for or add value to their fuel, and industrial companies may want to assure reliable electricity supplies for their operations. Such vertical integration can have good economic and commercial rationales if the wholesale market is highly inefficient, but less so if the reforms have their intended effects of creating open and efficient markets. There is a widespread fear that the reason industrial interests want to control electricity assets is to

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[20] Russian law does not allow foreigners to own shares in RAO UES directly, but Russian companies that own shares in RAO UES can and do sell their own shares or "depository receipts" to foreign investors. These investors have done very well over the past few years, as RAO UES and some energo shares have soared in price.

[21] RAO UES inherited from the Soviet era a system with little debt (because of Soviet pay-as-you-go accounting), excess production capacity (because of the dramatic decline in the Russian economy), tariffs well below the full cost of new supplies and an inability to collect even these too-low tariffs from its customers. It has largely solved the collections problem (and is even recovering some of its old receivables), and now has a large, positive cash flow even though tariffs are still below replacement costs; given the low or zero book value of its assets and the absence of debt, this cash flow translates into high apparent profits.

improve or protect their positions elsewhere or to monopolize electricity itself (which would be feasible only in regions with limited transmission import capability).

Given that the objective of electricity reform in Russia is to end the RAO UES and energo monopolies, there is little possibility of and no point in strategic investments in the sector by Russian electricity companies. But foreign electricity companies should, in principle, be interested in such strategic investments. A foreign company could buy several generating plants or several distribution companies, add capital, technology and management resources, and create an efficient, profitable enterprise. There has been little foreign interest in such strategic direct investment in Russia, at least partly because there have been no strategic assets for sale in the market.[22]

Whatever their ultimate objectives, strategic investors by definition want to buy all of or at least controlling interests in companies or physical assets. Creating generation companies so large that they are indigestible to all but the largest strategic investors may or may not reduce the risks of capture by Russian oligarchs, some of whom – e.g., the large oil companies – could buy very large companies. But selling the sector in too-large pieces will limit the number of potential buyers, making it more difficult for the market to determine the structure of the sector and reducing the probability of strategic investment by foreign electricity companies with the technology and management that could make large improvements quickly.

3.1.4 Retail Competition for Small Consumers

Retail competition, at least for small consumers, is costly and difficult to implement, may have little benefit compared to alternative ways of supplying small consumers and is easy to get wrong with serious consequences. Even where retail competition "works" and is regarded as a success, the initial implementation costs have been so high – e.g., about a billion (10^9) US dollars in England and Wales – and the benefits have been so hard to demonstrate that the rate of return on investment has been small at best. More importantly, insisting on retail competition for small consumers complicates other parts of the market makes it more difficult to accomplish other objectives and increases the overall risk of getting something wrong. For example, it is hard for generators to get long-term contracts in a market with extensive retail competition, and the problems in California were due largely to a failure to recognize and properly deal with the conflicts between retail competition and predictable, stable retail prices.

Because of these realities, retail competition has advanced slowly everywhere and has even retreated where it was pushed hard initially, particularly in the United States. Retail competition will be even harder to implement in Russia than elsewhere for many reasons, including: the primitive state of the metering, settlement and billing systems, and of the legal and regulatory framework; the poverty and limited commercial experience of much of the population; and the institutional and social complexity of the traditional role of energos. It will be years before these

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[22] RAO UES is trying to interest a western company in signing a contract to manage an existing, new gas-fired combined cycle (GCC) plant near St. Petersburg, but has been unable to do so. Either the uncertainties of the Russian market are too great at this time or the management contract is unattractive – or both. A particularly unattractive feature of the contract is that it prohibits the contractor from buying the plant even if it is put up for sale at the end of the contract period.

and other problems can be overcome enough to make retail competition realistic or beneficial for most of the population of Russia.

Given this situation, Russia should consider explicitly delaying the introduction of retail competition for small consumers for five or ten years. The alternative – continuing to say that full retail competition is a near-term objective even though it cannot realistically be accomplished for many years – would create unrealistic expectations, divert scarce institutional and financial resources from the accomplishment of more important and realistic objectives, and increase the risk that inefficient and ineffective forms of retail competition might be adopted. It would be better to acknowledge that retail competition for small consumers is not practical or beneficial for many years, and to take advantage of the simplifications this would allow.

Removing retail competition as a near-term objective of the reform program could have the following effects:

- Large consumers could still get the benefits of competition by joining the wholesale market or contracting with one of a few specialized competitive suppliers. The resulting hundreds or thousands of wholesale market participants would be easy to manage compared to adding millions of small, unmetered, unsophisticated consumers and the multiple competitive suppliers necessary to serve them.
- The retail supply business could remain a regulated monopoly affiliated with the distribution business; there would be no need to split these businesses, to create separate competitive suppliers and guaranteed suppliers (GS), or to deal with the many difficult regulatory problems caused when competitive and regulated businesses exist side-by-side.
- The regulated monopoly suppliers could be required to enter into contracts for their electricity supplies, using a regulated competitive process to choose contract suppliers and define contract prices; regulation of this process would not be easy, but something similar would be required for the regulation of GS under the current plan.[23]
- If the contracts entered into by monopoly suppliers had long enough terms, they could provide generators with the long-term contracts investors say they need to justify investments in the Russian electricity sector.

Given the difficulties created by trying to make full retail competition a reality or even a serious objective in the short run, the alternative of explicitly removing it as an objective for some years is worth consideration.

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[23] The 5+5 Plan says that a GS will simply pass through the wholesale price. But the only unambiguous definition of "the wholesale price" is a spot market price, perhaps averaged over a metering/billing period of a month or so after the fact, and there is usually strong political opposition to exposing small consumers to wholesale price risk even on a monthly-average basis. If a GS is to pass through some projected or contract price, regulators must decide which contracts represent the market, whose forecasts should be relied upon, who should bear the costs when forecasts are inaccurate or when contract prices turn out to be above market, etc. A process in which regulated retail suppliers use a competitive process to contract with wholesale suppliers is often, and increasingly, used in the United States, even in those states in which full retail competition was (or still is) the stated objective.

3.1.5 The Regulatory Processes and Institutions

The regulatory processes and institutions of the target market, as mentioned in the introduction, are the subject of the separate policy note on regulation. These matters are mentioned here only to reinforce the point that electricity regulators have far less independence, resources, experience and authority in Russia than they do in any of the other countries that have created competitive electricity markets.

Improving the capacity of Russia's regulatory processes and institutions to the point where they can deal adequately with a competitive electricity industry (which is not the same as bringing them to a level comparable to regulators in advanced market economies) will take time and resources, probably more time than is available under the current restructuring schedule and more resources than are available under likely regulatory budgets. It is unlikely that restructuring will be delayed to wait for regulatory capability to catch up, but proceeding with restructuring when regulatory processes are so undeveloped increases the risk that the structure or activities of the new companies will reduce the competitiveness and efficiency of the market.

There is no good way to resolve this dilemma. But the dilemma does suggest that it would be unwise to rush the restructuring process, particularly where the benefits are small and the regulatory burdens large, such as retail competition for small consumers.

3.2 The Restructuring Process

Even the best target structure and market do not guarantee the success of an electricity (or any other) reform program: the transition process must also be well designed and implemented. Several features of the process outlined in the 5+5 Plan deserve comment in this regard.

3.2.1 The Aggressive Timetable with Parallel Paths

The timetable for accomplishing the RAO UES restructuring and implementing the wholesale market is very aggressive given the magnitude of the task and the available resources. Setting aggressive schedules and sticking to them as long as possible can help overcome the natural bureaucratic – and human – tendency to delay making changes, but can also increase the risk that serious mistakes will be made. And schedules that clearly cannot be met may simply be ignored.

According to the timetable laid out in the 5+5 Plan (pp. 34-35), by 2006 (whether early or late in the year is not clear) the restructuring described above will be largely complete (apart from the trading of shares to adjust GRF's holdings in different companies) and fully liberalized wholesale and retail markets will be beginning operating across all of Russia except in some isolated systems and the Far East. If this timetable is met even approximately, the Russian electricity restructuring and reforms will have been accomplished more rapidly than almost any other, even though it was more complex and difficult.[24] In reality, this timetable is highly unlikely to be met.

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[24] The implementation of full retail competition within a few years will have been particularly remarkable. Designing and implementing retail competition for small consumers has typically taken five years or more even in systems with far better information systems (e.g., metering, settlement and billing) and more advanced commercial and regulatory institutions.

If overly aggressive schedules caused nothing worse than embarrassment or higher costs when deadlines were missed and had to be relaxed, they would not be a serious problem. But the real risk posed by unrealistic schedules is that some of the many things that should move in parallel will fall behind others, letting some parts of the reform program get too far in front of others. Such an imbalance can result in decisions or actions being taken in the more advanced part of the program that should not be taken until the slower parts have caught up. There is a serious risk of that happening in Russia.

The Russian electricity reforms have two very different but equally critical parts: the structural and market reforms being discussed in this policy note, and the institutional and regulatory reforms discussed in the other policy note. The structural and market reforms are largely business processes under the control of RAO UES, which has the resources and the motivation to push them forward, while the regulatory reforms are bureaucratic matters controlled by the GRF, the Duma and administrative agencies who may have fewer resources, less motivation and less knowledge about how to get the job done. In this situation, the restructuring and privatization of the RAO UES and energo businesses may go forward faster than the reform and staffing of the regulatory institutions needed to control the new private companies. The newly liberated businesses might then be able to change the structure, create local monopolies, establish inefficient market arrangements, etc., in ways that advantage themselves at the expense of the market generally before the regulatory institutions are in a position to monitor or control their actions. To prevent such an imbalance from developing and threatening the long-run success of the reforms, the GRF and RAO UES should consider slowing the restructuring/privatization effort and accelerating the regulatory/institutional effort.

3.2.2 The Complexity of the Restructuring Process

The restructuring process outlined above is incredibly complex, involving creating, merging, and liquidating hundreds of companies within a few years. The market development process is also very complex, involving implementing the 5-15 Market, expanding it in depth and geographic coverage, and then replacing it with the target LMP/FTR market. Trying to introduce full retail competition within a few years would add a whole different set of complex issues and processes.

Some of the complexities in the restructuring process could be reduced by relaxing some of the near-term objectives. One obvious and effective way to reduce complexity would be to take retail competition off the table as an objective for some years. Another would be to put less emphasis on creating large generation companies initially, so that some RAO UES or energo generation assets could be sold directly into the market. Yet another would be to move directly to a LMP/FTR market with vesting contracts rather than continue developing the highly flawed and probably counterproductive 5-15 Market. Canceling or delaying some supposedly intermediate objectives may appear to be delaying the overall program, but would not be if the intermediate objectives are themselves questionable and primarily add to the difficulty of making real progress toward a desirable end state.

Even when all reasonable simplifications to the process have been made, getting to some version of the standard competitive electricity market model from where Russia is now will still be a complex process. That inherent complexity should be kept in mind when setting a timetable for getting there. Unrealistic deadlines are unlikely to help the process.

3.3 Wholesale Market Design and Retail Pricing

The target wholesale market design, with its integrated dispatch/spot market process to determine the dispatch and LMPs simultaneously, FTRs available for hedging the congestion charges implied by locational price differentials and contracts for differences (CfDs) used for bilateral electricity contracts, is consistent with the standard model. But the 5-15 Market that is now operating has flaws that make it problematic as a useful transition to the target LMP/FTR market, contracts are already being used to exempt some market participants from congestion prices in the 5-15 Market in ways that will create serious problems if continued under the target LMP/FTR market; and the issue of long-term capacity payments or contracts to supplement the spot market and short-term contracts is yet to be resolved. Finally, there are serious questions about whether retail prices will ever be allowed to increase enough that wholesale prices will support new generation investment when it is needed. These issues are discussed in this section.

3.3.1 The 5-15 Market

The most serious problem with the 5-15 Market is that its prices have very little to do with reality or with the prices that would be produced by a reasonably designed LMP market. The most obvious cause of this problem is that demands have, in effect, an option to buy at regulated prices in any hour in which the prices in the 5-15 Market are higher, while generators must sell as much as they can in the 5-15 market at almost any price. As a result, prices are consistently too low, and particularly at peak periods when they should be high.

A more subtle problem with pricing in the 5-15 Market is that the LMPs used for settlement there may be very different from the LMPs that, if calculated, would reflect the real costs of real congestion given the way the physical system actually operates. This difference between the two sets of LMPs arises because the settlement LMPs are determined in the ATS' second SCED run, which uses supply and demand bids to find a hypothetical dispatch that meets the hypothetical market-determined demands, while the "correct" LMPs are those that are – or could be, if the objective function were less artificial than it is – determined in the ATS' first SCED run, which determines the actual dispatch that meets actual expected demands.

Because the LMPs that reflect real congestion are not used for settlement purposes, the prices in the 5-15 Market may be very misleading as a guide to the level and pattern of LMPs and congestion expected in the target LMP/FTR market. Furthermore, generators may often be dispatched against implicit LMPs that are very different from the LMPs they are being paid, which will create incentive and gaming problems. A principal purpose of the 5-15 market is to give market participants experience with market processes, LMPs, congestion prices, etc., to help them get ready for the target market; unfortunately, as the 5-15 Market is now operating, it is given market participants a highly misleading picture of what to expect and how to behave in a more efficient LMP/FTR market.

These problems may not be too serious for too long, because the 5-15 Market may quickly become irrelevant. The too-low prices in the 5-15 Market and the differences between settlement LMPs and the real LMPs will give generators strong incentives to be constrained on or off so that they collect regulated prices rather than the market price. If smarter generator bidding increases market prices to something closer to regulated prices, demands will have little reason to bid in the market. The 5-15 Market may just fade away.

Even if trading in the 5-15 Market does increase to something like the 15 percent target, the logic of this market is so far removed from that of a real LMP-based market that is no effective way to expand the scope or efficiency of the market over time to provide a smooth transition to a true LMP-based market – even though the 5+5 Plan says (p. 19) that this is the intention. At some point, the 5-15 Market will have to be replaced with something very different, and most of the experience and learning gained by using it will become irrelevant or even counterproductive. If the 5-15 Market proves more successful than suggested here, there will be strong opposition to scrapping it for an alternative that is untried, will produce very different prices and will require very different commercial and bidding strategies. If the 5-15 Market proves unworkable and fades away, or creates serious problems, system operators and market participants may lose faith in markets altogether. The 5-15 Market provides neither a good testing ground for market processes nor an effective transition path to the target market model.

It might be possible to reduce the problems with the 5-15 Market by correctly computing LMPs in the ATS' first SCED run and using these to settle all real-time quantities in excess of the market-determined quantities. But this would require so many *ad hoc* fixes to the market mechanics and systems, and such large changes in participants' expectations and behavior that it would be better to move as soon as possible to a different transition strategy.

The obvious alternative transition strategy is to implement the target LMP/FTR market as soon as practical, but with a system of vested commercial CfDs in place to protect market participants from the full effects of market prices. The market processes and LMP calculations used during the transition would be the same as those of the target market, but demands and generators would have virtually full contract cover initially so that regulated/contract prices would be paid for essentially all production and consumption initially. Over time, the level of vesting contract cover would be reduced so that market participants' exposure to market prices would gradually increase; as market participants became more exposed to market prices they could decide either to live with this exposure or to begin entering into commercial contracts to protect themselves. The target market situation would emerge gradually with no sudden shift from one set of market processes, bidding strategies and LMPs to another – which is how a transition should work.

It would take at least several years to design and put in place the target LMP/FTR market and the vesting contracts, and in the meantime it would be necessary to continue relying on regulated prices (and the 5-15 Market if this proves more workable than suggested here). With this timing, the transition process outlined here could begin with what is now called (p. 19) Phase IV of the 5+5 Plan, now scheduled (probably unrealistically) for 2006, when the full target market is supposed to be introduced throughout Russia except for isolated systems and the Far East. This looks like a slow-down in the schedule, but if the conclusion here about the 5-15 Market is correct – i.e., the 5-15 Market will not provide a useful transition to the LMP/FTR market – then it would not really be a slowdown because the current schedule will not be met anyway.

3.3.2 The Form and Effect of Electricity Contracts

The 5+5 Plan says that bilateral contracts for electricity under the target market arrangements will be financial CfDs. A CfD is – or at least can and should be; contract language can vary – explicitly not a contract for the purchase and sale of physical electricity, but is a financial contract under which the buyer and seller agree to make monetary payments to one another based on the difference between the contract price and a specified market price (or price index).

As long as both contracting parties can buy and sell physical electricity in the same open and efficient spot market, a CfD (combined with FTRs in a LMP market) can be used to accomplish any commercial purpose that a so-called "physical" contract can and, because CfDs are so flexible, even more.[25]

Although it is correct to say that all electricity purchase and sale contracts under the target market arrangements will be CfDs, some market participants in Russia are demanding "physical" contracts instead or in addition to CfDs. A demand for so-called physical contracts is common in all electricity markets before the market and financial contracting are understood and trusted, and is particularly understandable in Russia given the limited experience with and faith in markets and financial contracts. But there is no real advantage to, and not even a good definition of, physical contracts when there is an open and efficient spot market. A demand that some contracts be called "physical" is often little more than an attempt to create a separate class of transmission customers who get preferred use of the system without paying for it – e.g., the right to be dispatched and/or to take power when transmission congestion arises without paying congestion charges – and hence should be strongly resisted.

The notion that some contracts are different from others is already being used in Russia to get special treatment in the market. In the 5-15 Market, when a generator is located within 80 kilometers of its contract customer, neither party pays real-time congestion charges as long as the SO confirms in advance that "there are no essential system limitations [under] normal working conditions of electric networks between the supply points of the seller and purchaser." (paragraph 41 of GRF Decision No. 643, October 24, 2003, describing the transitional market arrangements). In practice, the SO tests for essential system limitations by modeling how power would flow on the system if only then-known contract transactions take place and the grid is fully available. But contracts will change, there will be spot transactions, and grid outages occur frequently, so real-time congestion may often appear even where the SO's modeling finds no "essential system limitations." Thus, the "physical" contracts in the 5-15 Market give contracting parties valuable transmission rights for which they pay nothing (officially) – and, like the 5-15 Market itself, give market participants unrealistic expectations about how the target model will work.

Exempting some market participants from the integrated spot market/dispatch process in this way is potentially unfair (depending on how much is paid for the implicit rights they get) and,

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[25] To illustrate the simplest form of CfD, suppose A contracts to sell to B the quantity Q (in MWh) in some hour at a contract price of P_C (in \$/MWh) at location X, where the spot market price in that hour will be P_X (in \$/MWh). The CfD will say only that A will pay to B the amount $(P_X - P_C)\times Q$ (in \$/hour) with respect to that hour (where a negative amount implies that B pays A). Both A and B then buy and sell at the price P_X whatever physical quantities they actually take from or deliver to X during the hour. The net result of the spot and contract transactions is that A is paid P_C for Q and is paid the spot price P_X for anything more (or pays P_X for anything less) than Q that it delivers to X, while B pays P_C for the quantity Q and pays the spot price P_X for anything more (or is paid P_X for anything less) than Q that it takes at X. In more complex cases, the CfD quantity and price can depend on anything the parties agree in the contract (e.g., the physical operations of either of them, or the weather), the payment can be made only if positive (or negative), etc.

more importantly, can distort operations and increase costs. Although the effects of such exemptions may not be serious under the 5-15 Market given the limited scope and other distortions of that market, serious problems could arise if the exemptions for contract transactions are continued in the target market. Market designers, legislative draftsmen and regulators should be alert for such possibilities.

3.3.3 Long-Term Capacity Payments or Contracts

The basic target market arrangements described in the 5+5 Plan contain no obligation on customers, suppliers or generators to maintain any specific level of generation capacity and no payments to generating capacity except those for energy (and ancillary services[26]) in the spot market. Generators are expected to sell much/most of their energy under contracts with suppliers or large consumers, but these contracts will be motivated by a desire to avoid being exposed to spot prices and hence the contract prices will reflect expected spot prices. The implicit assumption is that the prices emerging from the spot market – the LMPs – will be high enough on average to induce investments in baseload plants when and where these are needed, and will be high enough during critical or "scarcity" periods to induce investments in peaking capacity or load reduction options when and where these are needed.

The 5+5 Plan does suggest (p. 17) that a "capacity market (or capacity charge) can be introduced to ensure additional stable medium-term revenues to the electricity generators when the situation requires additional … investments in the generation sector … and smoothing of price fluctuations." This appears to be a late addition to the document and the Plan;[27] the profound implications of adding such a medium-term capacity payment to the target market do not appear to be fully recognized.

In theory, a well-designed and properly implemented energy spot market should produce spot prices high enough to induce investments in the optimal amount and mix of generating capacity. But it will do so only if the mechanics of the pricing process will produce very high prices under scarcity conditions and only if regulatory and political processes will allow such high prices

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[26] Ancillary services – e.g., operating reserves, reactive power, frequency control, black start capability – are not mentioned in the 5+5 Plan, were not mentioned by people interviewed in Russia and are not discussed here. But ancillary services are an important part of any electricity market, and payments for ancillary services are an important source of revenue for generators, particularly peaking capacity that may produce energy during only a few days a year. References in this note to "energy" should be read to mean "energy and ancillary services" when the context so indicates. There will be ancillary service markets, prices and contracts comparable to energy markets, prices and contracts, but the SO rather than suppliers or large consumers will usually pay and contract for ancillary services.

[27] The only references to a capacity market or capacity payments in the 5+5 Plan are on pages 16 and 17. On page 16 there are two references to the "three sectors of electricity trading," one identifying these three as bilateral financial contracts, the day-ahead market and the balancing market, but the other identifying these "three sectors" as bilateral contracting, the day-ahead market, the balancing market and "the power capacity market" as an uncounted fourth sector. Then a paragraph on page 17 says that "apart from the above three sectors … a capacity market (or capacity charge) can be introduced …" It appears that the notion of a capacity market was a late and incomplete addition to the document.

actually to be collected from (wholesale, not necessarily retail) demands and paid to generators. Occasional very high prices should not affect the overall economic situation of most generators or demands, because most electricity should be covered by bilateral contracts so that only incremental amounts are exposed to such high prices. In practice, occasional very high prices can be difficult to produce as a technical matter without raising market-power concerns, and difficult to tolerate as a political matter without raising demands for price caps.[28] Thus, even in sophisticated electricity markets, spot prices alone may not be adequate to stimulate enough investment to create the right amount and mix of generating capacity.

To make up for the inability of energy prices to become very high during scarcity periods, or to prevent such high prices, some markets use "installed capacity" (ICAP) mechanisms/markets to provide monthly or seasonal payments to all generating capacity that is installed or available during that period whether or not it actually produces and sells any energy during the period. Such ICAP mechanisms/markets are used primarily in the United States, where the ISO markets in PJM, New York and New England all have them – and have had continual conflict and controversy over them.

The price paid for ICAP during each (say) month is usually determined in some sort of market process, so that the monthly ICAP price is (very) high if the supply of ICAP is low compared to peak demand (for energy plus reserves) during the month, and the monthly ICAP price is (very) low if the supply of ICAP is much greater than peak demand during the month. Monthly ICAP prices add to the revenue a generator can expect to receive from the market, but tend to be highly volatile as the monthly capacity supply-demand balance changes from month to month. Such short-term capacity payment arrangements may do little to reduce long-term market uncertainty for generators or to convince regulators and politicians that "the market" will provide enough capacity several years in the future.

How the target market will determine LMPs under scarcity conditions, whether or not there will be an effective cap on LMPs, and whether or not there will be a short-term ICAP payment mechanism are all details of spot market design that will be decided later. The more fundamental capacity payment issue that should be addressed as a matter of policy now is whether there should be a centralized ***long-term*** capacity payment or contracting mechanism that would give generators a guaranteed revenue stream over many years, and if so what that mechanism should be.

Centralized long-term capacity payment mechanisms are often considered during the development of electricity markets in advanced market economies, but are usually rejected as unnecessary and unwise. The basic argument against such long-term capacity payment mechanisms is that they require somebody, either a regulator or the ISO that operates the market,

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[28] Sophisticated pricing mechanisms can produce very high spot prices under scarcity conditions by allowing prices to be based on demand bids or the deemed cost of overloading transmission facilities or taking energy from operating reserves, but these have seldom been implemented even in advanced electricity markets. Most US electricity markets include caps on spot prices at levels such as US$1,000/MWh, which is low relative to any reasonable estimate of the cost of involuntarily load shedding or of the scarcity prices required to induce investments in peaking capacity.

to make long-term projections and contract commitments for which market participants will ultimately pay even if their decisions are wrong. Because one of the main reasons to create an electricity market is to let investment decisions be made by private investors based on their own forecasts of market conditions, such a centralized long-term capacity mechanism is usually rejected – although the U.S. Federal Energy Regulatory Commission (FERC) continues to look for an acceptable long-term mechanism. If the short-term market mechanisms are well designed and properly implemented, the market will provide whatever long-term contracts and risk-sharing mechanisms are needed to stimulate investment.

The logic of the position against long-term capacity payments may be persuasive in an advanced market economy, but may be less so in Russia, with its relatively undeveloped capital markets and regulatory institutions, political uncertainties and limited experience with markets. The questions for Russia are whether these differences are so large that some sort of long-term capacity payment or contracting mechanism is required here – as some current and potential investors believe – even if it is not required elsewhere, and if so what that mechanism should be.

Whether or not the Russian electricity market should have a centralized capacity payment mechanism and if so what that mechanism should be are issues beyond the scope of this policy note. The point being made here is that any such mechanism will not be just a change in the details of the target market model that can be added as an afterthought, but will necessarily require some fundamental changes in that model that should be fully considered. The short-term market mechanisms – e.g., LMPs, FTRs and ICAP (if this is used) – can remain more or less the same, but it will be necessary to add a central planning and contracting agent that will decide how much of what kind of generating capacity is needed when and where, will make long-term commitments to that capacity, and will have to recover the costs of those contracts with what amounts to taxes on somebody. This can all be done in several different ways, some better (or worse) than others, but they all involve the same fundamental changes in market philosophy and processes, i.e., using a central planning/contracting/taxing agent to substitute for or at least supplement "the market" where long-term investment decisions are concerned.

3.3.4 Retail Prices, CHP Plants and Cross-Subsidies

Retail electricity pricing in Russia is complicated by the fact that a large fraction of electricity comes from CHP plants that also produce heat in a process with large common costs, resulting in constant uncertainty and political/regulatory battles over what the "true costs" of electricity and of heat really are. It is a fundamental economic reality that, in the absence of reliable market prices for at least one of such joint products, there is no way to know what either one of them really "costs," and attempts to answer this question by accounting allocations of joint costs usually create more confusion than information.

The retail pricing problem is further complicated by the division of regulatory responsibilities in Russia. Retail heat prices are set or at least strongly influenced[29] by regional regulatory authorities who are strongly influenced if not appointed by regional and municipal political

[29] The complexities of retail energy price regulation in Russia were compounded by the ongoing changes as this Policy Note was being written. The description of the process here is based on sometimes-conflicting information from those interviewed in Russia.

authorities, all under the oversight of a federal regulatory authority and subject to an overall cap on average electricity prices set by the GRF. The GRF's price cap is strongly influenced by macroeconomic (inflation) and political concerns and hence has been too low to cover the full long-run marginal costs (LRMC) of producing, transmitting and distributing electricity – although it is not clear what LRMC really is when so much electricity is produced jointly with heat and when "true" T&D costs are also uncertain.[30] Under this cap, the federal and regional regulators must balance often-opposing interests in several dimensions: consumers *vs.* producers; electricity consumers *vs.* heat consumers; small consumers *vs.* large consumers; etc.

The results of this process are retail prices that are widely agreed to be too low to cover the full costs of electricity and heat in the long run, combined with widely different views about what retail prices "should be," about the prospects for getting them "high enough," and about the economic value/viability of CHP plants and hence of the new TGCs that are to be created from them. Some people interviewed said that electricity usually cross-subsidizes heat, while others said that the cross-subsidies at least sometimes run the other way – but everybody agreed that the cross-subsidies would be hard to eliminate, whichever way they now run. Some said that trying to increase retail electricity prices to something like LRMCs any time soon would be politically and socially impossible, while others said that the relatively modest real price increases promised by the GRF over the next few years would do the job. Some said that CHP plants are not, and hence the TGCs will not be, commercially viable, while others said the CHPs/TGCs should do well in a liberalized market (perhaps because heat and electricity prices are expected to increase in such a market).

Given the limited time and resources available for preparation of this policy note, it is not possible to decide which of the opinions expressed above are correct; in fact, they may all be right in some specific situations. The most likely reality is that retail prices are generally too low now and will be hard to increase to LRMC levels – although given the current excess capacity in Russia, it may be many years before competitive wholesale prices will increase to LRMCs. The point here is that retail pricing is another difficult issue that will have to be solved before the competitive market can function well.

One key to resolving the (probable) conflict between politically acceptable retail prices and LRMC-level wholesale prices for new generation is a comprehensive portfolio of vesting contracts with existing generation. The vesting contracts will reduce the market value of the existing generators subject to them, but can be used to guarantee that retail prices do not increase quickly for small consumers even if wholesale prices do increase soon to LRMC levels (and will also help control generator market power). However, development of such a comprehensive set of vesting contracts is another big job that would be difficult to complete on the timetable now specified for the reform program. It is also a job that is much harder if there is retail competition

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[30] In some cases the LRMC of electricity generation is the cost of new thermal – i.e., non-CHP – generation. But where CHP is truly economic, the LRMC of electricity must be less (or at least no greater) than the cost of new non-CHP generation, by an amount that depends on the economic value of heat – which in some cases can be estimated from the cost to industrial customers of producing their own heat. So it is possible in concept to estimate the LRMC of electricity even from CHP plants, but only with a lot of analysis for a specific situation.

for small consumers, because in this case it is not clear who should be the counterparty to generators under the vesting contracts.

4. CONCLUSIONS

The size of the Russian system, the magnitude of the changes being made, the fact that so many changes are being made in parallel, and the complexity of interests that must be accommodated make the program described in the 5+5 Plan probably the largest and most complex electricity restructuring ever attempted anywhere. And it will have to be accomplished in an environment with poorly developed markets, weak regulatory institutions, significant private and official corruption, political uncertainty and a system of corporate law that is poorly developed overall but affords strong protections to minority shareholders.

Given all this, it has hard to escape the conclusion that the reform schedule is unlikely to be met, and that trying to stick to it will produce pressure to cut corners in ways that will compromise the final results but will still not meet the current schedule. It would be better to reduce the complexity of the job by dropping some intermediate objectives that add complexity and time to the process but little to the final outcome – i.e., retail competition for small consumers, the creation of large generation companies that may be attractive to portfolio investors but may not be attractive to strategic investors, and the flawed 5-15 Market – and then develop a more realistic schedule for the remaining, and still difficult tasks. If this is done, there is no fundamental reason why Russia cannot ultimately develop a workable and beneficial version of the standard electricity market model that is its ultimate objective.