PN-ACC-214

Russian Electric Power Market Operational and Financial Framework (REPMOFF)

Prepared for:

Joint Energy Alternatives Study
Working Group 5

Under Contract to:

U.S. Agency for International Development
Contract No. CCN-0002-Q-00-3152-00

Prepared by:

RCG/Hagler Bailly, Inc.
and
Energy Research Institute of Russian Academy of Sciences

April, 1994

ACKNOWLEDGEMENT

This framework for the Russian Electric Power Market was developed and implemented by Chitru Fernando, Sandra Robinson, Bahman Daryanian, and Shalabh Tandon, and the research staff of the Energy Research Institute of the Russian Academy of Sciences.

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Introduction

This report documents the Russian Electric Power Market Operational and Financial Framework (REPMOFF) implemented under the Joint Russian-American Energy Alternatives Study. This framework simulates the physical operation of the power system and alternative power market organizational structures, and performs a financial analysis of the impact of these alternative market structures. The framework combines the essential operational features of the physical structure of the Russian Power System with various market structures and dispatch rules. This framework provides a tool for detailed study of the economic and financial impact of various investment options on the entities that make up the power system and the impacts of potential electric power market alternatives being considered in Russia. It also analyzes the consequences of various physical changes to the system, such as changes in demand, plant capacity etc.

The framework's usefulness is highlighted by the fact that presently the structure of the Russian electric power system is undergoing a drastic reorganization. Both the Russian economy and its power industry are in transition. Presently, the ownership structure of the Russian electric power system consists of a number of national and regional entities, including the main national transmission and generation company, RAO EES Rossii, the nuclear generation company, and a number of regional generation and distribution companies or ENERGOs. The final ownership structure, the controlling interests, and the organizational form of the Russian electric power system is under discussion in Russia. There was a need for a framework to assist in both fashioning and analyzing the implications of various power market models and their implications on operations, policy options, financial settlements, and investment requirements. The framework enables study of the financial viability of each of the economic entities which constitute the power system under various power market structures. It also provides a basis for analysis and determination of wholesale prices in view of the revenue requirements of zonal or regional generation and distribution companies. The framework can be used to study and determine the wholesale and retail price and inter-zonal wheeling rate mark-ups which can be earmarked for national, zonal, or regional investment funds. Finally, the framework can be used as the basis of a simulation or planning model that will provide analysis of various generation and transmission investment options. The current operational level framework can be used to aid planning decisions over a short-run horizon (e.g. a year) like identifying the need for new power plants (e.g. due to closure of existing plants which have exceeded their design life), identifying the critical locations for investment in new power plants or transmission lines, analyzing ownership alternatives for new investments and analyzing the need for investment in various zones.

This work is part of the Joint Russian-American Energy Alternative Study (JEAS), Working Group 5, to develop a long-term, comprehensive investment program for the Russian Power Sector under the direction of the U.S. Agency for International Development and the Russian state electric power company RAO EES Rossii. The framework will be used by the Energy Research Institute (ERI) in Moscow for the study of power market alternatives for the

Russian electric power sector and for the analysis of various investment options.

Section I of this report provides a summary of the main features of the Russian Electric Power System. Section II describes the objectives and features of the framework. Section III discusses three types of alternative electric power organization structures that are simulated by the framework. Section IV discusses certain modelling issues specific to the Russian power system. Section V discusses extensions to the framework such as a Simulation Planning Model that are planned.

Appendix A describes the solution methodology used by the optimization program which determines the optimal operation of the electric network. Appendix B provides the operating instructions for the framework. Appendix C describes a list of terminologies used in the operational level model. Appendix D discusses the use of the model to simulate three scenarios based on the three alternative market structures and presents the input sheets of the model containing data set used for preliminary analysis. Appendix E contains financial outputs produced by the model for a specific market structure. Appendix F presents physical outputs produced by the model. Appendix G contains sample detailed outputs of the model.

I. Main Features of Russian Electric Power System

The Russian power industry, one of the largest in the world, provided 63% of the total electric power generated in the former USSR. In terms of fuel, technology, and research, it has been completely self-reliant. The Russian electric power system consists of an integrated network, i.e. Integrated Power System or IPS, which presently includes 8 (for modelling purposes) generation and demand zones.

The Russian power industry has a total generating capacity of more than 210 GW, providing about 1010 TWh (million MWh) of electricity production. About 70% of the power is generated by thermal power plants. Natural gas provides 54% of thermal plant fuel input, with the share of oil being 18%, and coal 28%. Nuclear power stations provide around 12% of the total electric power generated in Russia.

As is well known, recent events have necessitated drastic changes in the overall economy in general, and the power industry in particular. The direction of these changes have been from a completely centralized system towards a more free market structure with weaker governmental control. The decentralization process has accelerated by transforming the existing power production enterprises into joint stock companies.

To preserve the Russian integrated power system as a unified transmission network, and to provide open access to power producers and consumers, all transmission lines and their management structures were included to form the Russian Joint Stock Company for Power and Electrification (RAO EES Rossii).

There are about 72 regional power companies within the 8 aggregate zones engaged in both generation and distribution. However, of these, 20 had a surplus of power and the rest were either power deficient or had no generation capacity at all, which would have resulted in distortions in a competitive power market. Consequently, ownership of larger generation plants, i.e. hydroelectric power stations of 300 MW or larger, and thermal power stations of 1000 MW or larger, were transferred to RAO EES Rossii.

RAO EES Rossii presently manages the Central Dispatching Department, with six regional dispatch centers. The Ministry of Fuel and Energy has oversight policy control over RAO and the 72 regional power companies. A separate ownership is maintained for all the nuclear power plants, where the oversight responsibility is assigned to the Ministry of Nuclear Power. In addition, the Ministry of Economy is involved in the definition of the new Russian power structure in Russia.

Apart from ownership and organizational structure, other issues affecting the direction of the changes in the shape of the power market in Russia are the laws and regulations affecting operations and investments, and the institutional forms of related entities, such as regional power pools, federal and regional power commissions, banking and other financial institutions.

The shape of things to come will obviously affect the financial and operational viability of various market entities which constitute the power market system. Also affected will be such fundamental decisions as which entity determines the need for new power plants or upgrades of existing plants, the location of these power plants, who owns them, what level of investment is required, and where the investment funds come from.

II. Objectives and Features of the REPMOFF

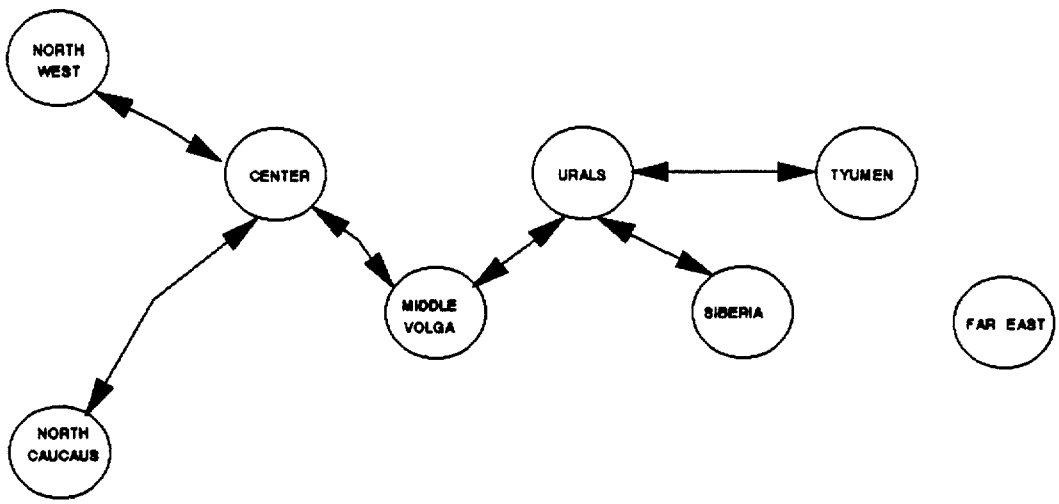
An important objective of the REPMOFF is to simulate alternative market structures for the Russian electric power system, with explicit financial accounting of various independent economic entities involved in the power market in order to determine their financial viabilities. The market options modelled here draw from practice in the US, UK and elsewhere but the framework has the flexibility to adapt these to the unique Russian context. This objective of the Operational Level Framework is in accordance with the expressed objective of the staff of Energy Research Institute (ERI) and the principal options modelled here have been developed jointly with them. In addition to simulating alternative market structures, the framework also performs an optimization routine which determines the optimal generation mix. The algorithm treats the electric power network as aggregate of zones and transmission lines with explicit treatment of inter-zonal flow limits. Due to the aggregate nature of the model there are at present no provisions for system security considerations similar to those of optimal power flow models. The model simulates the main operational features of the Russian power system and provides aggregate outputs for 8 regions over a short run period, usually, a year. Regional level analysis capability can be added for study of intra-regional impacts.

The framework organizes the Russian electric power sector into eight zones (equivalent to the present *Unified Electric Power Systems, UEPS*) based on ERI's information. Each zone is further classified into various generating plant types. These zones are connected via transmission lines. Figure 1 shows the power system zonal structure for Russia. This model performs optimization to minimize the total cost of dispatching electricity under alternative organization structures and under various system constraints like regional demand, generating plant capacities, transmission line capacities and other system constraints. The optimization model thus performs a least cost dispatch (generation mix) and provides various physical outputs to the Operational Level Framework for further financial analysis. The framework then provides various financial results for analysis, under various market structures, which include (i) Income statements for various economic/ institutional entities involved in the market structure, (ii) Various electricity prices and tariffs and (iii) Shadow prices for various generating plants and transmission lines. The physical and financial results provided by the model also aid in planning decisions like identifying the need for new investment in plants and lines due to various reasons, analyzing the need for investment funds in each zone to meet any new investments in plants and lines, identifying key zones which need investments in plants or lines and other planning decisions over a short run horizon (a year, for instance). Future versions of the model can be extended to simulate a longer time horizon in order to aid longer term planning decisions. The following sections would discuss in detail all the analysis supported by the Operational Level Framework.

A. Basic electric power sector organization structure

The framework assumes an underlying electric power organization structure as a basis

Fig 1. Power System Zonal Structure



for developing alternative scenarios. The basic structure comprises of four types of institutional/economic entities involved in the electric power market:

- *Generating Companies:* Various generating plants in the zones can be assigned to independent generating companies. The framework is flexible enough to incorporate any type of ownership structure for the generating plants e.g. a company can own all the plants in a zone or it may own all plants of a specific type or it may own any other combination of plants distributed across various zones.

- *Grid Company:* The grid company (equivalent to the present *Integrated Power System grid, IPS grid*) owns the entire transmission grid for Russia and is responsible for the maintenance of transmission lines and for the flow of power across various regions. For these services the grid company would levy a tariff (referred to as the "grid tariff") on the distribution companies. The terms "grid company" and "national grid" are used interchangeably in this report.

- *Zonal Pools:* The market structure would have one pool per zone. However, the framework would be flexible enough to allow the analysis of combining zonal pools into a single pool. Each zonal pool is responsible for importing power from other zonal pools and for exporting power to other zones while meeting the demand in its zone. Under alternative market structures the prices for trading (i.e. importing/exporting) of electric power between zones would be decided. The zonal pool also buys electric power from the generating plants of its zones and then sells the net power accumulated by the zone (after the trading) to the distribution companies at wholesale electricity prices.

- *Zonal Distribution Companies:* For simplification purposes, the current framework assumes one distribution company per zone. Each distribution company buys power from its zonal pool and then sells it in the retail market. Each distribution company also pays the grid tariff to the grid company.

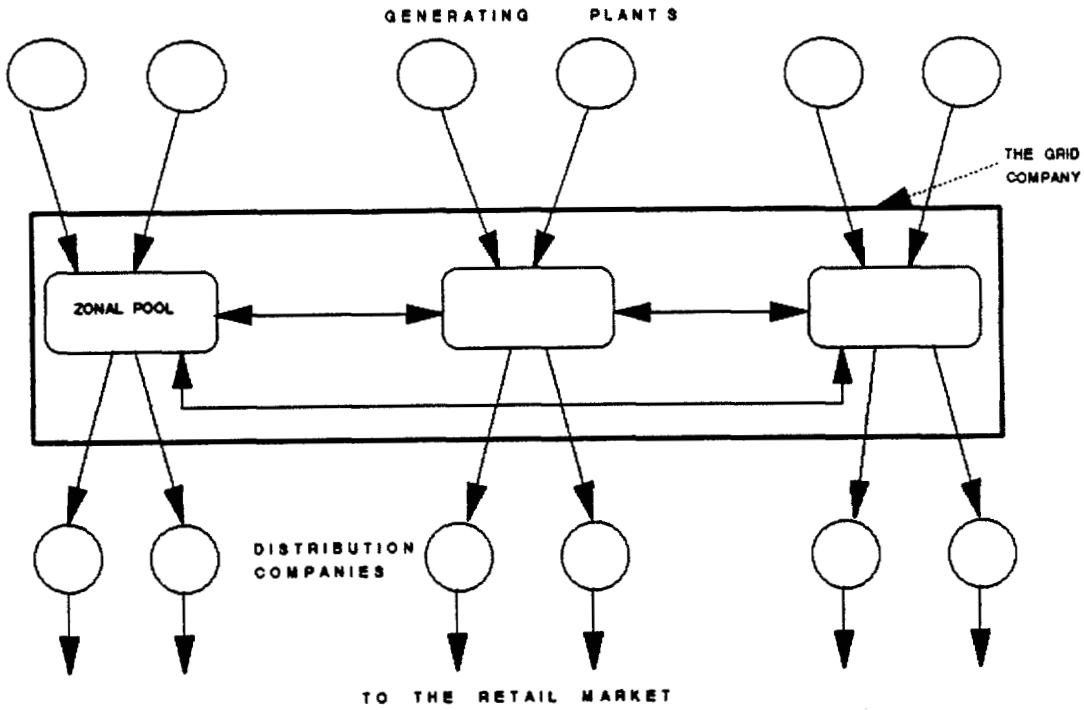
Figure 2 depicts the power flows between the various entities constituting the Russian electric power system.

The following sections would discuss in detail the framework for analyzing electricity pricing and financial statements of various economic entities under various market structures. The following is a list of definitions related to electricity prices and tariffs:

- *Pool Purchase Prices (PPPs):* Pool purchase prices are the prices at which a zonal pool buys electricity from the generating plants within its zone. These prices may be different for different plant types within each zone and could be different across different zones depending upon the market structure.

- *Zonal Trading Prices (ZTPs):* Zonal trading prices are the prices at which electric power is traded between various zonal pools. These may be different between different sets of

Fig 2. Power Flows in the Industry



zones.

- *Wholesale Electric Prices:* Wholesale electric prices are the prices at which zonal pools sell electricity to the zonal distribution companies. The framework can compute break-even wholesale prices for each zone so that each zonal pool is able to recover its costs. This will help facilitate realistic wholesale prices that each zone can charge in order to make some profit and use part of that profit towards future investments.

- *Grid Tariff:* Grid tariff is the tariff paid by the zonal distribution companies to the grid company. This tariff could be different for different distribution companies.

- *Retail Electric Prices:* Retail prices are the prices at which the zonal distribution companies sell electric power to retail customers. The framework can also compute break-even retail prices for each zonal distribution company. The break-even retail price is the price at which a zonal distribution company recovers all its costs.

B. Dispatching methodology

Each generating plant has a dispatch price associated with it. The dispatch price takes on different values under different scenarios e.g. in one scenario the dispatch price could be the variable fuel costs of generating electricity, while in another scenario it can be the bid price for generating electricity. The optimization model takes as input the dispatch prices and various electric power system constraints and parameters and provides a least-cost dispatch which minimizes the total cost of dispatching electricity under various scenarios to meet the electricity demand. The total cost of dispatching electricity is the total cost paid by all the zonal pools combined to all the generating plants. The optimization model uses a network flow approach for optimization.

C. Data used as input by the framework

At the operational level, the framework takes in as input the following data:

- *System Parameters:* These include the zonal structure of Russia, the existing generation and transmission capacities, the short term zonal demand patterns, the variable costs (fuel, operating and other variable costs) associated with each plant type, the bid prices of generation (if any), uncertainties associated with demand fluctuations and plant and line breakdowns, and other system parameters (e.g. line losses) and scenario specific inputs. Appendix D contains (i) the data used as input by the Operational Level Framework and (ii) Printouts of input sheets of the framework.

- *Financial/Market parameters:* These parameters include the following:

(i) Settlement prices: These are the prices used for financial settlement between the generating plants and the zonal pools. These prices could be bid prices or a function of variable costs of plants under various market scenarios. Settlement price is the least price that each generating plant would settle to sell its energy under any market structure. In the current model, the last three plants in each zone are modelled as LM (Load Management) or DSM (Demand Side Management) technologies. The settlement price of these plants would be the cost of load management or demand side management.

(ii) Dispatch prices: These prices are usually the same as the settlement prices and are used by the optimization model to perform a least cost dispatch. However, under certain circumstances a dispatch price may be different from a settlement price to force a desired dispatching behavior.

(iii) Zonally differentiated grid tariffs: The framework would simulate the effect of charging different tariffs on the financial statements of various economic entities.

(iv) Wholesale electricity prices: Wholesale electricity prices for each zone could be set exogenously by the user. The framework would also provide as output some benchmark break-even wholesale electricity prices.

(v) Retail electricity prices: The framework would simulate the effect of charging various retail prices on the income statements of the distribution companies. The framework would also provide as output some benchmark break-even retail prices.

(vi) Fixed costs for generating plants, overhead costs for generating companies and fixed and overhead costs for the grid company, the zonal pools and the distribution companies.

(vii) Variable costs for all economic entities wherever applicable, e.g. line maintenance costs for the grid company.

(viii) Ownership structure for various generating plants.

D. Outputs and financial analysis supported by the framework

The main outputs reported by the Operational Level Framework include the following:

- All physical outputs related to the dispatch of electric power, e.g. actual generation, power flows, demand met, shortages etc.

- All financial transactions between various economic entities.

- Income statements for all economic entities i.e. the generating companies, the zonal pools, the grid company and the distribution companies.

- Average benchmark wholesale electricity price that each zonal pool can charge to the distribution companies in order to recover all its costs.

- Average benchmark wholesale electricity price for the entire system.

- Average benchmark retail electricity price that each zonal distribution company can charge to the retail customers companies in order to recover all its costs.

- Average benchmark retail electricity price for the entire system.

- Shadow prices for each generating plant and each transmission line.

- Other aggregate financial and system outputs e.g. trading of power between zonal pools, plant and transmission line utilizations etc.

Benchmark electricity prices

The following are benchmark electricity prices reported by the model:

- Benchmark Zonal Wholesale Prices: Yearly or daily benchmark zonal wholesale price in R/MWh for each zone. The benchmark zonal wholesale price for a zonal pool is the break-even price for that pool. It is the price at which the zonal pool can sell its energy to the distribution companies so as to recover all its costs i.e. it is the price at which *"revenue from sale in wholesale market + export earnings = cost of buying power from generating plants + import costs + fixed & overhead & investment costs"*. The benchmark price is thus the least price that a zonal pool can charge to recover all its costs.

- Average System Wholesale Price: Yearly or daily benchmark system wholesale price in R/MWh for the entire system. This price is computed by dividing (the total payments made to the generating plants by all the zonal pools plus the total fixed & overhead & investment costs of all zonal pools) by (the total consumption of power in the entire system). It is the least average wholesale price that each zonal pool can charge so that the total costs for all the pools combined is recovered.

- Benchmark Zonal Retail Price 1: Yearly or daily benchmark zonal retail price 1 in R/MWh for each zone. Benchmark retail price 1 is the break-even price at which a zonal distribution company can recover all its costs *assuming that the distribution*

company buys power in the wholesale market at benchmark zonal wholesale prices. Thus, this price is the least price that a zonal distribution company can charge to recover all its costs. The costs to a distribution company are the costs of buying power in the wholesale market, the grid tariff payments made to the national grid and the fixed & overhead & investment costs.

- Benchmark Zonal Retail Price 2: Yearly or daily benchmark zonal retail price 2 in R/MWh for each zone. Benchmark retail price 2 is the break-even price at which a zonal distribution company can recover all its costs *assuming that the distribution company buys power in the wholesale market at the wholesale prices input by the user.* Thus, this price is the least price that a zonal distribution company can charge to recover all its costs. The costs to a distribution company are the costs of buying power in the wholesale market, the grid tariff payments made to the national grid and the fixed & overhead & investment costs.

- Average System Retail Price 1: Yearly or daily benchmark system retail price 1 in R/MWh for the entire system. Average system retail price 1 is the least average retail price that each zonal distribution company can charge so as to recover the total costs for all the distribution companies combined *assuming that the distribution company buys power in the wholesale market at benchmark wholesale prices.*

- Average System Retail Price 2: Yearly or daily benchmark system retail price 2 in R/MWh for the entire system. Average system retail price 2 is the least average retail price that each zonal distribution company can charge so as to recover the total costs for all the distribution companies combined *assuming that the distribution company buys power in the wholesale market at wholesale prices input by the user.*

Shadow prices

The model provides as output the shadow prices for generating plants and transmission lines over the time horizon of the model, usually a year.

- Plant shadow price: Shadow price of a plant is the *reduction* in the total payments received by all generating plants in a year due to 1 MW increase in the capacity of the plant, all other system parameters remaining unchanged.

- Line shadow price: Shadow price of a line is the *reduction* in the total payments received by all generating plants in a year due to 1 MW increase in the capacity of the line, all other system parameters remaining unchanged.

Shadow prices can also be treated as the marginal benefits arising due to 1 MW increase in plant or line capacity. Shadow price is a useful planning tool as it aids in identifying critical locations requiring new investments in plants or lines. Zones containing plants with high shadow

prices are usually more critical for investment than zones containing plants with lower shadow prices. The same is true for lines too. However, a good analysis of shadow prices would require comparing the shadow price or marginal benefit of a plant or line with the marginal cost of investment in additional capacity for that plant or line.

Income Statements

Based on the optimization output, the framework would support financial analysis of the electric power market structure by providing aggregate income statements for the following:

Income Statement for a generating company:

Revenue from sale of power to zonal pools	xxx
Less Variable operating costs	xxx

Gross Margin	xxx

Less Fixed costs	xxx
Overhead costs (may include investment)	xxx

Income	xxx

Income Statement for a zonal pool:

Revenue from sale of power to distribution companies	xxx
Plus Revenue from export of power to other zonal pools	xxx
Less Cost of buying power from generating plants within the zone	xxx
Cost of importing electricity from other zones	xxx

Gross Margin	xxx

Less Fixed & Overhead & Investment costs	xxx

Income	xxx

Income Statement for the grid company:

Revenue from grid tariff levied on distribution companies	xxx
Less Line maintenance expenses	xxx

Gross Margin	xxx

Less Fixed & Overhead & Investment costs	xxx

Income	xxx

Income Statement for a distribution company:

Revenue from sale of power to retail market	xxx
Less Cost of buying power from wholesale market	xxx
Cost of paying grid tariff to the grid company	xxx

Gross Margin	xxx

Less Fixed and Overhead costs	xxx

Income	xxx

III. Alternative Electric Power Sector Organization Structures

REPMOFF simulates three fundamental power market structures. These three fundamental structures were developed after carefully analyzing existing power market structures prevalent in privatized economies of the world e.g. the UK market structure and the US market structure. The three alternative market structures simulated by this model are (i) Type A: uniform system-wide marginal price based payments to generators (ii) Type B: uniform zonal marginal price based payments to generators and (iii) Type C: generator specific settlement price based payments to generators. The essential difference between the three market structures is the level at which the marginal price based payments to generators are uniform. Under Type A market structure all generators receive payments linked to a uniform marginal price for the entire system. Under Type B market structure all generators receive payments linked to uniform marginal price of its zone i.e. a zonal marginal price is uniform for all the generators in that zone. Under Type C market structure there is no concept of a uniform marginal price based payments to a group of generators. Instead, all generators are paid based on their specific settlement prices for generation which may or may not be based on their marginal costs.

The following sections discuss in detail the three types of market structures. The above described differences between the three market structures are the main differences. All other differences that arise are non-fundamental in nature. In all the three market structures, a generating plant can bid for electricity in an open market bidding system or can settle to sell energy at its marginal cost of generation or at its variable cost of generation. Thus, the settlement price for a plant in any of the three market structures (as defined in Section II and as used in the model) can either equal the bid price or be based on the cost. The optimization program of the model performs a dispatch based on the dispatch prices and does not distinguish whether the settlement prices have been set using bid prices or using cost based prices. However, Type A and Type B market structures support settlement prices being equal to bid prices more than Type C market structure. Type C market structure supports settlement prices being based on the costs of generation for specific plants. The strategies for trading of power between various zonal pools has currently been assumed to be the same for all three market structures. However, future versions of the framework can simulate alternative inter-zonal trading strategies.

1. Type A: Uniform system-wide marginal price based payments to generators

This market structure bears similarity to the *UK model* in that the dispatch of electricity is usually based on the bid prices for generation submitted by independent generating plants and the computation of a uniform system-wide marginal price. It must be noted, however, that the settlement price can also be based on variable cost of generation.

A. Market structure

This market structure is based on the basic market structure with the four economic/institutional entities - generating companies, zonal pools, grid company and distribution companies.

Under this market structure various private generating plants would bid for generation of electric power. Specifically, a plant would bid a price (e.g. in Rubles/MWh). This is referred to as the bid price for that plant. The plant would also bid its available generating bid capacity (e.g. in MW). Various plants would ordinarily bid different prices depending upon their respective variable costs for generation, the competitive market environment and other market driven forces.

Electric power is purchased from the generating plants by the zonal pools at a uniform **system-wide marginal price (SMP)** which is the same for all the zones. In addition to purchasing power at SMP, the zonal pool also makes certain other payments to certain generating plants. These payments are termed as **constrained-on payments or uplift payments.** The exact nature of these constrained payments are discussed later.

B. Dispatch of electricity

The optimization program will provide a least cost dispatch schedule i.e. the least total cost to all the pools of buying electricity from the plants to meet as much demand as possible under various system constraints. The dispatch price for each plant is usually the bid price of the generating plant, unless an artificial value is entered for the dispatch price to force certain dispatch behaviors. In this market structure, the optimization model runs at two levels: (i) An unconstrained run and (ii) A constrained run.

The unconstrained run establishes a merit order dispatch (without performing any optimization) and computes the system marginal price (SMP) based on the settlement prices and bid capacities of plants and the total demand of electricity for Russia. The unconstrained run neglects the transmission line constraints for transfer of power between zones. The merit order is established by ranking all the generating plants in ascending order of their settlement prices and then satisfying the total demand in that order. The plant with the highest settlement price in the merit order is termed as the marginal plant and its settlement price is the system marginal price (SMP). **Figure 3a** shows the SMP based settlement for generation in a UK style structure.

In the constrained run, the model considers the transmission line limits and performs optimization to minimize the total costs to all the pools of purchasing power from the generating plants. The constrained run provides the final real time dispatch of electric power. After a constrained run, there would exist two types of generating plants - (i) Constrained Off (C-Off) generating plants and (ii) Constrained On (C-On) generating plants. Constrained Off generating plants are those which exist in the unconstrained merit order but in the constrained run, their

Fig 3a. SMP based settlement for generation (UK Style)

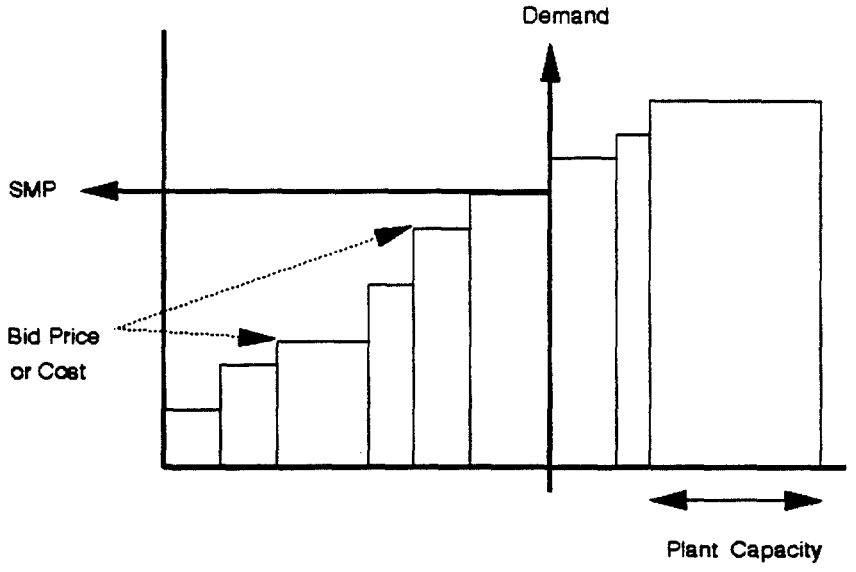
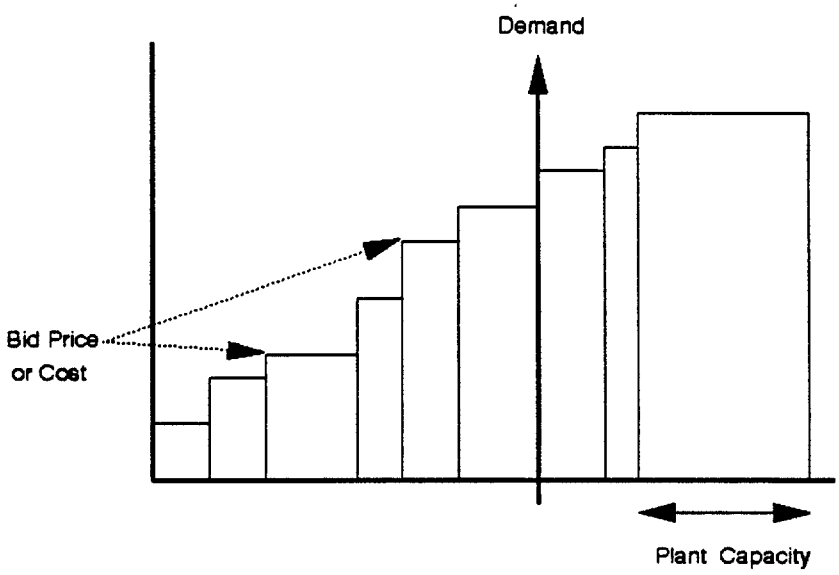


Fig 3b. Cost based settlement for generation (US Style)



scheduled generation is less than that in the unconstrained run. Constrained On (C-On) generating plants are those whose scheduled generation in the constrained run is greater than that scheduled in the unconstrained run. The payments made to these two types of plants are different.

C. Financial settlements

Figure 4a shows the financial flows between various economic entities in this market structure. Financial settlements between various economic entities are based on the following procedure:

- Do the unconstrained run based on settlement prices to establish the merit order and to determine the system marginal price (SMP).

- Do the constrained run based on dispatch prices (usually equal to settlement prices) by considering transmission constraints and establish the constrained generation schedule.

- Determine marginal price of each zone by setting zonal marginal price (ZMP)= settlement price of most expensive plant that generates electricity in each zone. This could be the cost of demand side options. If a zone has no generation at all, its ZMP is undefined. If, however, the ZMP of a zone computes to less than SMP then it is set to SMP. This is because in this market structure each generating plant receives at least SMP for a unit of energy. Hence, no trading of energy can be made at prices lower than SMP.

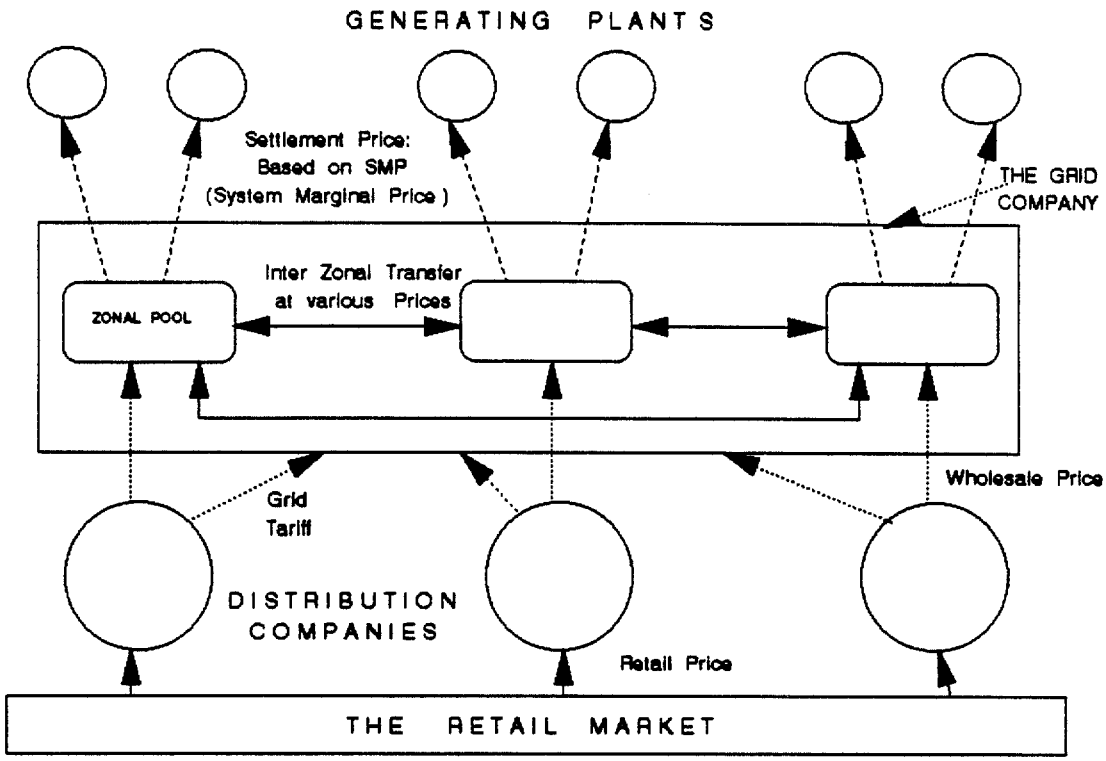
- Each zonal pool pays all the constrained-on generating plants in its zone their settlement prices for their actual generation in the constrained schedule. The amount of payment made to a constrained-on plant over and above SMP is termed as constrained-on payment or uplift payment. All other generating plants in the zone are paid SMP based on their actual generation in the constrained schedule.

- Each zone is established as either a net exporter or a net importer of power. A net exporter sells power at its ZMP to a common non-profit pool. From the common pool all net importers buy power at the weighted average cost to the common pool of importing power. Thus inter-zonal transfers are through a common non-profit pool. All net importers buy at the same price although the net exporters sell at different prices.

- Each zonal pool sells electricity to its zonal distribution company at wholesale electricity prices. If all the zonal distribution companies have to pay the same wholesale price, then a basis for such a wholesale price could be SMP plus some mark up.

- Each zonal distribution company sells electricity in the retail market at the retail electricity prices.

Fig 4a. Financial Flows for Type A Market Structure (System Based)



- Each zonal distribution company pays the grid tariff to the grid company based on the actual amount of power distributed by the company.

- Determine the difference between total cost of constrained run and total cost of unconstrained run. Allocate this as a mark-up above SMP by dividing by the total quantity of consumption. This value is an indication of additional constrained costs due to transmission constraints.

2. Type B: Uniform zonal marginal price based payments to generators

This market structure bears similarity to the *UK model* in that the dispatch of electricity is usually based on the bid prices for generation. However, it is different from the UK model in that it has no uniform system-wide marginal price. It only has zonal marginal prices just as in Type A market structure. As under Type A market structure, the settlement price of a plant can also be cost based.

A. Market structure

This market structure is identical to that of Type A market structure with plants usually bidding for electricity except that there is no concept of a uniform system marginal price (SMP). There is also no unconstrained run and hence no concept of constrained-on or constrained-off generating plants. Zonal Marginal Prices (ZMPs) are computed in this market structure in the same manner as in Type A structure.

B. Dispatch of electricity

The optimization program will dispatch electricity to minimize the total cost to all the pools of buying electricity at dispatch prices from all the generating plants in order to satisfy as much demand as possible under various system constraints like plant capacities, line capacities etc. The dispatch price for each plant is usually the settlement price of the plant.

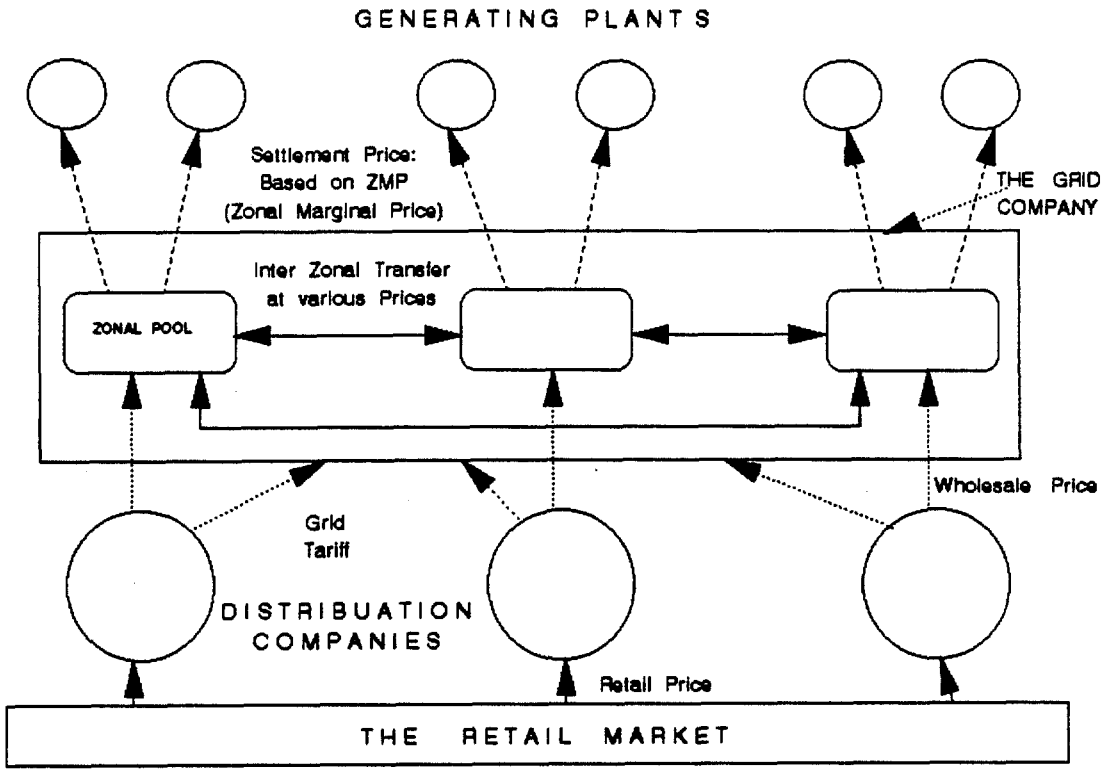
C. Financial settlements

Figure 4b shows the financial flows between various economic entities in this market structure. Financial settlements between various economic entities are based on the following procedure:

- No unconstrained run and hence no SMP determination.

- Do the constrained run based on dispatch prices (usually bid prices) by considering the

Fig 4b. Financial Flows for Type B Market Structure (Zonal Based)



transmission constraints and establish the constrained generation schedule.

- Determine marginal price of each zone by setting zonal marginal price (ZMP)= settlement price of most expensive plant that generates electricity in each zone. This could be the cost of demand side options. If a zone has no generation at all, then the zone's ZMP is undefined.

- Each zonal pool pays all the generating plants in its zone the ZMP of the zone they are located in.

- Each zone is established as either a net exporter or a net importer of power. A net exporter sells power at its ZMP to the common non-profit pool. From the common pool all net importers buy power at the average cost to the common pool of importing power. Thus, inter-zonal financial settlements are made exactly as in Type A market structure.

- Each zonal pool sells electricity to its zonal distribution company at wholesale electricity prices.

- Each zonal distribution company sells electricity in the retail market at the retail electricity prices.

- Each zonal distribution company pays the grid tariff to the grid company based on the actual amount of power distributed by the company.

3. Type C: Generator specific marginal price based payments to generators

This market structure bears similarity to the *US model* in that the dispatch of electricity is usually based on variable costs of generation. Fig 3b shows the cost based settlement for generation. It must be noted, however, that although under this market structure the settlement price is usually cost based, the settlement price can even be based on the bid price.

A. Market structure

This market structure also has the same four economic entities as in the earlier two market structures. However, there is usually no bidding of electricity done by generating plants. Instead the dispatch price for each generating plant is usually its variable cost of generating a unit of power plus some profit markup. The zonal marginal prices (ZMPs) are based on these variable costs (variable costs + markup). Since this market structure has no concept of an SMP, there is no concept of constrained-on or constrained-off generating plants.

B. Dispatch of electricity

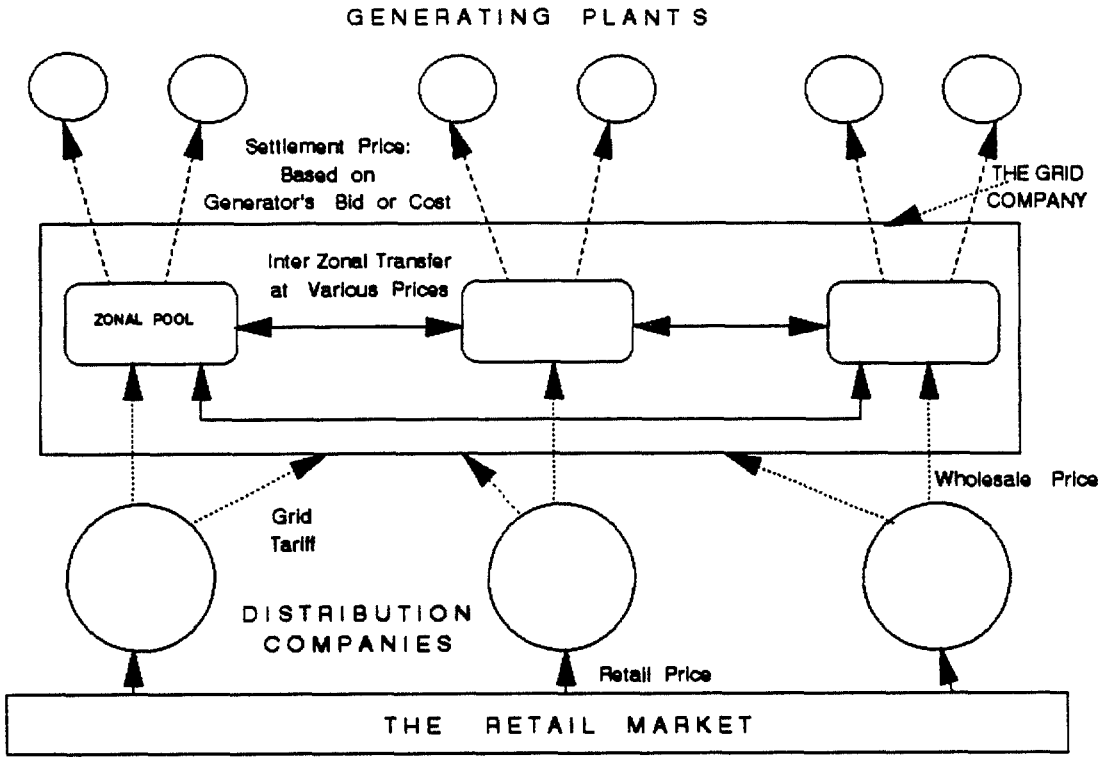
The optimization program will dispatch electricity to minimize the total cost to all the pools of buying electricity at dispatch prices from all the generating plants in order to satisfy as much demand as possible under various system constraints like plant capacities, line capacities etc. The dispatch price for each plant is usually based on the variable costs of generation.

C. Financial settlements

Figure 4c shows the financial flows between various economic entities in this market structure. Financial settlements between various economic entities are based on the following procedure:

- No unconstrained run and hence no SMP determination.
- Do the constrained run based on dispatch prices (usually based on variable costs) to determine the impact of transmission constraints and establish the constrained generation schedule.
- Determine marginal price of each zone by setting zonal marginal price (ZMP) = variable cost for the most expensive plant that generates electricity in each zone. As before, this could be the cost of demand side options. If a zone has no generation at all, then the zone's ZMP is undefined.
- Each zonal pool pays all the plants in its zone their respective settlement prices which are usually variable costs plus profit markup.
- Inter-zonal transfers are the same as in Type B structure i.e. net exporters sell their power to the common pool at their ZMPs, and then net importers buy power from the common pool at an average price.
- Each zonal pool sells electricity to its zonal distribution company at wholesale electricity prices.
- Each zonal distribution company sells electricity in the retail market at the retail electricity prices.
- Each zonal distribution company pays the grid tariff to the grid company based on the actual amount of power distributed by the company.

Fig 4c. Financial Flows for Type C Market Structure (Generator Based)



IV. Modelling Issues Specific to the Russian Power System

There are modelling issues which are specific to the Russian power system. These issues may or may not exist in the new evolving power market structure in Russia. These issues are discussed below. The Operational Level Framework can support the simulation of these issues under all the three types of market structures discussed earlier.

Dispatch price versus settlement price

Because of the need to model various power market structures based on different dispatch criteria, it is necessary to define a dispatch price which can be set artificially based on the underlying power market structure. The dispatch price takes on different values under different market structures as has been discussed in the previous section. However, in the Russian power system there may be a need to artificially set the dispatch price for some of the generating plants in order to artificially force the dispatching behavior of these plants. The dispatch price for these plants may be significantly different from the settlement price.

Hydro Plants

In the Russian system, Hydro plants are dispatched at peak load times due to limited total energy and availability, although the running costs of the hydro plants are negligible. Consequently, in the model, an artificially high dispatch price can be set for the hydro plants to ensure dispatching only at peak times. For financial accounting purposes, the actual variable costs or actual bid prices are to be used as settlement price, whichever is applicable.

Bi-Directional Line Capacities

In the Russian system the aggregate transmission capacity limits between the zones depend on the direction of the flow. This necessitates bi-directional treatment of the lines.

Treatment of Combined Heat/Power Plants

In the Russian system, the combined heat/power plants are dispatched primarily on the heating requirements. This means that in typical winter day-types, 85% of the capacities of these plants are used as base electrical load from midnight to 7 a.m. and 100% from 7 a.m. to midnight. These ratios are 50% and 60%.

Therefore, when district heating is in effect, from the dispatching perspective, these plants are viewed as having zero dispatch prices. Therefore, the dispatch prices for combined

heat/power plants need to be set to zero in the model. For financial accounting purposes, the correct price to use is the variable cost or bid price, as applicable.

Accounting for Plant Maximum Hours Usage Per Year

In the Russian system, there are limits on the minimum and maximum hours per year each plant or plant-type can be utilized. Since all plants of the same type would not be out at the same time in each zone, then the total available capacity of each plant-type can be adjusted by de-rating of the plant-type.

The de-rating is based on multiplying the total capacity of each plant-type by the ratio of the maximum hours usage per year for each plant type (HMAX) to the total number of hours in the year (8760). Therefore, the adjusted capacity for each plant or plant-type i is:

$$adjcap[i] = \left(\frac{HMAX}{8760}\right) \times totcap[i] \qquad (1)$$

Due to the special data structure available in Russia, it is possible to assign a number days for each day type that sum up to less than 365 days. The main reason is that for planning purposes, installed capacities are considered for winter peak day only. Using the hourly load curves for this day type and the historical data on load factors, the yearly energy consumption is equivalent to about 240 to 280 days of this particular day type.

Consequently, it is possible to use the actual installed capacity without derating for the peak hour, and then assign availability or utilization multipliers (a number less than or equal to 1) for each period of the day for each plant type. This can be done in the "Constrained Input Area" of the model. The advantage of this method is more accurate representation of certain plant types such as Hydro and Combined Heat/Power whose availability may depend on the period the day.

Using more day types to represent other seasons of the year, and the seasonal availability of plant types, a more accurate simulation is made possible.

V. Extensions to the REPMOFF

A. Extensions

Extensions to the present model can increase its capabilities as a versatile planning and analysis tool. The following is a list of extensions that are underway or under discussion with ERI:

- Incorporating Power Exports outside Russian power system, Reserve Margins, and Capacity Gaps.
- Modelling other power market and ownership structures.
- Simulating financial contracts between various entities.
- Predicting behavior of power companies in a free market (to inform the design of regulatory schemes).
- Providing information on primary fuel usage in power generation and modelling the impact of conservation and fuel switching.
- Providing the environmental impacts of various scenarios and options.
- Determining the effective cost or price benchmark for DSM (Demand Side Management) technologies under various scenarios and options.
- Incorporating other options for financial settlement of inter-zonal economy interchange, such as Split-Savings Rules.

B. Simulation Planning

REPMOFF is being used in analysis of various investment options by comparing snap-shots or scenarios of each option on a year by year basis. This process is being automated by developing a multi-year Simulation Planning Program, which uses the Operational Level Framework as its core single-year operational engine. The present model is an optimization program based on Chronological Load Shapes , in contrast to the main engine of other integrated resource planning programs which are based on load-duration curves. Furthermore, the Simulation Planning Program will include all the Power Market Structure and Financial Operations options included in the Operational Level Framework.

The Multi-Year Simulation Planning Program is summarized as follows:

- Define the option under study: Start with the base (current) year plant/line configuration of the power system, and select a plant/line construction/retirement option. Options for system improvement and investment can be based on Sensitivity Analysis and analysis of shadow prices for each of the generation and transmission constraints.

- Provide electricity demand values (or rates of change in demand) for each year in the planning time horizon.

- Provide data for fuel cost and electricity rates (wholesale and retail) for the future years.

- Determine the annual fixed cost of each old or new plant

- To simulate the operations for a multi-year time horizon, run the Operational Level Framework for each year in the time horizon, and determine the (operational) physical and financial results for each year. Combine the yearly results for the whole time-horizon.

A number of options and scenarios can be run in the preceding fashion to compare the overall results, and choose the best alternatives. The Operation Level Framework is versatile in terms of the physical and cash-flow outputs, and as a result, the Simulation Planning Program will be an effective Investment Planning tool. If need be, an Optimal Planning Program can be developed at a later date based on Dynamic Programming Formulation using the Operational Level Framework as its main engine.

APPENDIX A

Solution Methodology for the Optimization Program

Optimization problem

The optimization problem consists of minimum cost dispatching of the plants based on their dispatch prices, subject to the plant capacity constraints and transmission line limits. The following terminology is used here:

p	pth period, in hours
r	rth zone
i	ith plant
dispr[i]	dispatch price of plant i
varcst[i]	variable cost of running plant i
linecap[r1,r2]	capacity of aggregate transmission between zone r1 and zone r2
gen[i]	generation of plant i
gencap[i]	generation capacity of plant i
ZMP[r]	zonal marginal price for rth zone based on constrained merit order of plants sorted on dispatch prices in rth zone.

The objective function to be minimized is:

$$\textit{Objective Function} = \sum_{i}^{I} \left(gen[i] \times dispr[i] \right) \tag{2}$$

Where I is the set of all plants
Subject to the following constrains:

- For each plant i:

$$gen[i] \leq gencap[i] \tag{3}$$

- For each transmission between zone k and l:

$$flow[k,l] \leq linecap[k,l] \tag{4}$$

- For each zone k:

$$\sum_{k}^{K} gen[k] + \sum_{l}^{L} flow[k,l] + shortage[k] = demand[k] \tag{5}$$

where K is the set of all zones and L is the set of all zones excluding k.

Plant dispatch prices are defined by the type of power market structure and dispatch rule in effect. For instance, in the American model, a plant dispatch price is the variable cost of the plant operation. In the British model, a plant dispatch price is defined by either the system marginal price, or the bid price of the plant, or if there is a fixed price contract, by the so-called exercise price.

Solution methodology

The optimization problem is cast as a linear programming formulation, and thus, it can be solved by any linear programming methodology such as simplex or any applicable transportation or network flow algorithm.

The method used here is based on a network flow algorithm combined with a shortest path algorithm. The algorithm starts with an initial feasible solution, i.e. an initial feasible combination of plant generations which together satisfy demands of all regions without any violation of plant and flow constraints. Then, starting with the initial feasible set, the algorithm substitutes more expensive plants with less expensive plants across all regions while satisfying all the given constraints. The process is continued until the optimal set is determined which results in a final feasible set of plant commitments satisfying all of the constraints at a minimum-cost.

American model

The American power market consists of an independent utility and a number of utility owned generation plants. Plants are dispatched according to their variable costs:

$$dispr[i] = varcst[i] \tag{6}$$

subject to the same constraints as defined previously.

British model

The British power market consists of an independent national grid and a number of independent generation and distribution companies. Dispatch is based on the so-called system marginal price, SMP, determined on the basis of merit order of plants ignoring the transmission capacity limits between zones. SMP is the bid price of the plant on the top of the stack of plants in the unconstrained set which together provide sufficient capacity to satisfy the total aggregate demand of all zones. Plants are stacked up in ascending order of their bid prices. The capacity of plants which are included in the unconstrained set are referred to as unconstrained capacities. Additional terminology used in the British model are:

bidpr[i]	actual bid price of plant i
exrpr[i]	contract exercise price of plant i
bidcap[i]	bid capacity of plant i, equivalent to gencap[i]
SMP	system marginal price based on constrained merit order of plants

In actual dispatch, when the transmission constraints between zones are taken into account, the actual capacity of plants used may be less or more than the unconstrained capacities. The actual plant capacity used is referred to as constrained capacity. The plants are paid for the actual capacity used in SMP per MWh. These are called energy payments. For any plant which is in the constrained set, but not in the initial unconstrained set, there are further payments which are referred to as C-ON constrained payments. By definition, a plant which is not in the initial unconstrained set has a bid price which is greater than SMP.
The C-ON constraint payment is:

$$\textit{C-ON Constrained Payment} = gen[i] \times (bidpr[i] - SMP) \tag{7}$$

The model includes one type of contract, a simple price contract, where the bid price of plant is set at a fixed exercise price.

The objective function to be minimized is the total cost to the grid of the energy and constrained payments to the generators. Here, we denote the group of plants belonging to the initial unconstrained set as group U. The plants which are not in the initial unconstrained set are defined as group N. Then the total costs to the grid are:

$$\textit{Total Grid Costs} = \textit{Energy Payments} + \textit{Constrained Payments} \tag{8}$$

or

$$\begin{aligned} \textit{Total Grid Costs} = & \sum_{u}^{U} (gen[u] \times SMP) \\ & + \sum_{n}^{N} (gin[n] \times SMP) \\ & + \sum_{n}^{N} [\, gen[n] \times (bidpr[n] - SMP) \,] \end{aligned} \tag{9}$$

or

$$\begin{aligned} \textit{Total Costs} = & \sum_{u}^{U} (gen[u] \times SMP) \\ & + \sum_{n}^{N} (gen[n] \times bidpr[n]) \end{aligned} \tag{10}$$

Therefore, for optimization purposes, the dispatch price of the plant in the U group is set to SMP, and the dispatch price of the plant in group N is set to its bid price (or exercise price if there is a contract). Hence,

- If plant i is in the initial unconstrained set, then

$$dispr[i] = SMP \tag{11}$$

- If plant is not in the initial unconstrained set, then

$$dispr[i] = bidpr[i] \tag{12}$$

Therefore using i as the plant index, the objective function to be minimized is:

$$Objective\ Function = \sum_i^I \left(gen[i] \times dispr[i] \right) \tag{13}$$

Inter-zonal financial settlements

In the case where all the plants and all the pools and the grid are owned by one company, there is no need for inter-zonal financial settlements. However, if there are multiple economic entities operating in the market, there is a need for a mechanism to formalize the financial transactions for the inter-zonal power transfers.

A simple mechanism proposed here is to set the inter-zonal payments based on the exporting zone marginal prices (ZMPs). The steps involved are:

- Determine the optimal generation mix for the over-all grid based on the defined plant dispatch prices.
- For each zone determine the highest settlement price of all the plants in operation.
- Identify the zones as *net exporters* and *net importers* of power.
- Evaluate the net total export from all export zones at the start point of transmission, $EXPORT_T$, and the net total import for all import zones at the end point of their transmissions, $IMPORT_T$. Denote the ratio of total net export to total net import as the Loss Multiplier.
- For each net exporting zone, the export sales price is set at its zonal marginal price (ZMP).
- Set the import price for all net importers as the (weighted) average of export prices weighted by the net export from each zone multiplied by the loss multiplier.

Therefore, if zone i is a net exporter, then:

$$Export\ Price\ at\ zone\ i = ZMP_i \tag{14}$$

If zone j is a net importer, then:

$$Import\ Price\ at\ zone\ j = Loss\ Multiplier \times \frac{\sum_i^I (EXPORT_i \times ZMP_i)}{\sum_i^I EXPORT_i} \tag{15}$$

where, I is the set of all net exporters, and $EXPORT_i$ is the net export of electricity in the period from the export zone i, and the Loss Multiplier is defined as:

$$Loss\ Multiplier = \frac{EXPORT_T}{IMPORT_T} = \frac{\sum_i^I EXPORT_i}{\sum_j^J IMPORT_j} \tag{16}$$

Based on this simple financial transaction mechanism, all the import payments and export earnings balance out.

APPENDIX B

Russian Electric Power Market

Operational and Financial Framework

(REPMOFF)

Software User Instructions (REPMOFF Version 1.1)

Russian Electric Power Market Operational & Financial Framework

(REPMOFF Version 1.1)

Software User Instructions

INTRODUCTION

REPMOFF is a simulation and optimization program with an embedded model of the Russian Electric Power System. The model determines the optimal generation mix under different Power Market Structures. The model explicitly accounts for aggregate transmission constraints between zones. The Integrated Power System of Russia, IPS, is represented by 8 zones in the model, where each zone is equivalent to the zonal Unified Electric Power System, such as North West and Center. The zones include all the generating plants and companies in the network, by grouping the power generating plants in each zone into plant-types, and assigning them to different company configurations.

The last three plants in each of the zones are reserved for outage technologies (load management, demand side-management, etc.) and shortages. There is space allocated for the addition of more plants in each zone.

Three are three general Power Market Structures represented in this model. The Type A power market structure is based on system-wide marginal pricing (SMP) payments. If dispatch prices are set to individual plant bid prices, then the Type A power market structure becomes similar to the simplified British model. The Type B power market structure is based on the zonal marginal pricing (ZMP) payments. The Type C power market structure is based on actual settlement price payments. If plant dispatch prices are set to plant variable costs, then the Type C Market Structure becomes similar to the American model.

REPMOFF can model three Day Types. A year, or a month, or a week can be represented by a combination of these Day-Types. For example, a week can consist of 5 days of Day-Type 1, 1 day of Day-Type 2, and 1 day of Day-Type 3. Furthermore, each Day-Type consists of (up to) nine periods such that the total time of the nine blocks is twenty four hours.

The outputs of the model consist of detailed and aggregate physical and financial results for plants, companies, zones, and the grid. The physical outputs include period by period, day by day, and yearly optimal plant generations and transmission flow rates. The financial outputs include plant, company, zone, and grid cash flows for periods, days, and the year. The model also provides benchmark values for wholesale and retail prices, and shadow prices for plant and line capacity constraints.

REPMOFF is written in the *C* programming language, with a *Lotus 1-2-3* user interface for inputs and outputs. The optimization is done using a Network Flow algorithm built into a

C program which is invoked automatically from Lotus *1-2-3*. Macros are provided so that the user simply inputs data for the run (bid prices, expected demands etc.), instructs the model to run, and then examines the results. REPMOFF operates on a standard IBM-compatible personal computer with at least 4 MB of RAM that should have the capability to run *Lotus 1-2-3 (Release 3.4)*.

REPMOFF consists of 5 different 1-2-3 spreadsheet programs, DOS based executable programs, and a number of ASCII based input and output files. The spreadsheet programs are:

REPOINP.WK3:	The main user input and output interface, which controls the optimization program flows.
REPOAGGR.WK3:	Includes the aggregate physical and financial results.
REPO1.WK3:	Includes the aggregate and detailed physical and financial results for Day Type 1.
REPO2.WK3:	Includes the aggregate and detailed physical and financial results for Day Type 2.
REPO3.WK3:	Includes the aggregate and detailed physical and financial results for Day Type 3.

Section I describes in detail the User Inputs. Section II describes the process of running the model and the relevant menus and commands. Section III lists some cautions which the user of this model must adhere to. Section IV describes the procedure for installing the model.

I. USER INPUTS

The inputs are of three types: plant-by-plant information (capacities, bid prices, etc.), transmission lines (capacities), and expected demands in each region. By far the majority of the inputs concern the plants.

Many of the inputs, e.g. demand and capacity, can be changed from period to period within a run. Others, are usually fixed for the entire run.

Plant Specific Inputs

The Plant-specific inputs are:

- Zone Code: This specifies the region or zone to which the corresponding plant belongs.
- Company Name: This is used only in the company specific aggregation of results in the Cash Flow Summary.
- Plant name: This is normally an identifier e.g. "HPP, NPP, or LM1 ".
- Plant Variable Cost: These are the variable operating costs of each plant in Rubles/MWh.
- Bid capacity: These are the declared generator capacities in MW (Re-declarations of capacity due to outages are handled randomly, as described later.) For outage technologies they are the maximum actual load reduction; these are not used in calculation of the unconstrained run in the Market Structure Type A. At least one plant in the model should be labeled "LM", i.e. Load Management, with a high capacity and price to prevent the optimization results becoming infeasible.
- Settlement Price: For conventional generators, these are the standard bids, in Rubles/MWh. If periods correspond to different days, they can be changed from period to period within a run by overwriting the old value; otherwise they should remain fixed.

  For the last three plants (LM / outage technologies) in each region the settlement price must be set to an equivalent Load Management or Demand-Side Management cost per MWh. If LM is to represent shortages, then the price should be set to the expected cost of shortages, or zero in most cases.
- Dispatch Price: These are operating prices used in the optimization for plant dispatch in Rubles/MWh. Dispatch prices are usually equal to settlement prices. In certain cases, however, dispatch prices may be artificially set in order to induce a particular intended dispatch behavior. In general, if shortages are to be avoided, then the price must be set

to a very high value (higher than any actual plant or DSM cost). In other words, shortages are represented by zero settlement prices but very high dispatch price. As a result, shortages are considered as the last available option when dispatching, but in case they occur, there are no actual or settlement costs involved.

- Generator Availability Factor: These are factors by which plants are derated for the given day type. It is recommended that these factors be used to represent availability after reserve and other considerations that affect the usage of the plant during the peak hour. The availability factors which depend on the period of the day or day type should be input in the "Constrained Input Area" of the model.

OTHER INPUTS

- Line Capacities: Specifies the capacity of each transmission line in the capacity column. The net transfer capacity of a line is the line capacity specified in the input area multiplied by the factor of "alpha".

- Total Line Maintenance Costs: These costs are given per period per day.

- Hours per period: The 24 hours of the day can be at most be divided into 9 periods. The length of each period should be specified in hours.

- MW demand expected: The forecast MW demand in each region for each period is specified in these columns. Actual demands used to calculate actual dispatch are adjusted by the stochastic parameters, described elsewhere. It is recommended that in this input area, all periods of the day be assigned the peak demand value. Then the demand multipliers in the "Constrained Input Area" be used to scale demand for each period of the day.

- Scenario: This input specifies the name of the scenario and its description.

- Num Days: This input specifies the number of days per year represented by the particular Day Type

- Loss Factor: A linear line loss factor between 0 and 1 is entered here. This loss factor reflects the linear loss of flow across the aggregate transmission and is modelled in the optimization using a heuristic which attains a sub optimal dispatch in the presence of line losses.

- Stochastic Inputs: Three of the inputs are subject to random variability between the declared and actual values: plant capacity, transmission lines, and demand. The Optimization Program uses the randomized values. Simple binomial random numbers are used in the randomization. At present each plant is randomized based on the same

probabilities, and similarly for lines and demands. Randomization in each period is independent of previous periods.

- plants: The actual plant capacities are randomized based on two parameters: pi and Sigma.p. Pi is the probability that the plant is fully available. (Pi =1 means no chance of reduced output.) Sigma.p is the capacity multiplier if capacity is reduced. For example pi = .7, Sigma.p = .95 means a 30% chance that output of a plant will be 95% of nominal.

- lines: The parameter lambda is the probability that a line is available. Lambda equal to 1 means no outages. If a line goes out, it goes out completely. For example a lambda of 0.7 means that there is a 30 % chance that a line breaks down during a constrained run. The parameter line.d is the multiplier used to reduce line capacity in the stochastic mode.

- demand: Demand may be revised upward by multiplying by parameter sigma(u), or downward by parameter sigma(d), each of which should be close to 1.00. The probability of a downward revision is given by delta1, while the probability of an upward revision is given by 1-delta2. The probability that demand equals its forecast is therefore delta2-delta1. For example if (sigma(d), sigma(u), delta1, delta2) = (0.95, 1.05, 0.3, 0.7), there is a thirty percent (0.30) chance of demand being 95% of forecast, thirty percent (1 - 0.70) chance of being 105% of forecast, and a forty percent (0.70 - 0.30) chance of demand equaling the forecast. Note that this is applied to each region independently.

o <u>Seed:</u> An integer value between 1 and 1000 can be entered here. The seed is used when the model is run in the stochastic mode. Subsequent runs having the same seed will generate the same set of random numbers. Thus, the seed is very useful in replication of randomized runs and hence in comparing the effect of various decisions on the same set of stochastic/randomized runs.

o <u>Market Structure:</u> Specifies the Type of Power Market Structure.

o <u>Alpha:</u> This variable accepts a value between 0 and 1. The line capacity is multiplied by this factor (Alpha) to compute the transfer capacity of the line.

o <u>Multipliers:</u>

The "Multipliers Input Area" supports the modelling of actual plant availability at different periods, and variations in declared versus actual zonal demand. Plant capacity Multipliers can be viewed as plant availability factors or plant de-rating factors. Therefore, actual plant capacity gets de-rated by the multipliers. The following are the inputs in the "Multipliers Input Area":

- Flag: Setting the Flag to 0 instructs the model to use the Generator Availability Factor from the main input area to determine the availability factors for all periods. In effect, the model will copy the generator availability factor into the Multiplier Input Area for each plant and each period of the day type. Setting the Flag to 1 instructs the model to ignore the Generator Availability Factor, and instead use the availability factors individually entered in the Multiplier Input Areas. Furthermore, setting the Flag to 0 also prevents the optimization from adjusting the demand by the demand multipliers.

- Plant Availability Factors: Plant availability factors are the multipliers by which plant capacity is scaled for each period of the day type.

- Demand Multipliers: Demand multipliers are the factors by which the zonal demand for each period within a day type is scaled.

o Zonal Pool Fixed & Overhead & Investment Costs: Fixed & overhead & investment costs in each zone

o Zonal Distribution Co. Fixed & Overhead & Investment Costs: Fixed & overhead & investment costs for the zonal distribution companies (One distribution company in each zone).

o Zonal Wholesale Price: The wholesale price charged by the Grid for the power sold to the zonal distribution companies.

o Zonal Retail Price: The retail price charged by the zonal distribution companies for the power sold to their customers.

o Zonal Grid Tariff: The tariff charged by the national grid or IPS to zonal distribution companies.

II. RUNNING THE MODEL

The following steps describe how the model is run.

Load the Model (REPOINP.WK3)

- o Switch to the Lotus 1-2-3 Rel. 3.4 system directory (or C:\REPO directory) and type: 123 and [Enter]. This program will load the memory resident portion of Lotus 1-2-3.

- o If the REPO directory has not been set as the default directory, select [/File Directory] and then type C:\REPO and [Enter].

- o Load REPMOFF by selecting [/File Retrieve] and then select REPOINP.WK3 and [Enter].

- o If after retrieving the file, the main menu does not appear at the top of the screen, press [Alt M].

- o The Main Menu and accompanying screen will appear. From this menu you may specify assumptions for up to nine periods, run optimization for any of the nine periods, inspect results, or exit.

  The Main Menu and other menus in the REPMOFF work like other Lotus 1-2-3 menus: You make selections by simply typing the initial letter (or number) in the name of the selection. You may also move the cursor left or right in the control panel at the top of the screen, then press the [Enter] key.

Provide Inputs

- o From the Main Menu, press [INPUTS..], and the Inputs Menu and the accompanying screen appear.

  -- Press [DAY1...], or [DAY2...], or [DAY3...] to input data for each Day Type:

  - Press [BIDS..] to enter plant capacity, price, and other data. You may make entries in any of the highlighted cells. Note that the list of plants extends beyond the visible screen: use the arrow keys to reach all plants and all columns. The [PgDn] and [PgUp] keys are not available in this mode.

    When finished, press the [Enter] key without first entering data in a cell, and you will return to the [INPUTS..] Menu.

- Press [LINES..] to enter line capacity and line maintenance costs. This screen and other data input and most output inspection screens work similarly to the Bids screen. When finished, press the [Enter] key without first entering data in a cell, and you will return to the [INPUTS..] Menu.

- Press [DEMAND..] to enter, first, duration of time periods, and then, demand by time period. (Press an extra [Enter] to proceed after entering duration.)

  Period duration is limited to 24 hours to keep results within display formats. You may scale results up for any longer time periods.

- Press [SCENARIO..] to enter particular scenario data and stochastic variables:

  - Enter number of days represented by the Day Type.

  - Enter the Line Loss Factor (between 0 and 1).

  - Enter stochastic (probabilistic) variables to determine whether and within what bounds random effects will be generated to modify plant, line, and demand assumptions. These effects add realism but complicate comparison of scenarios. To suppress random effects, enter "1" for all stochastic parameters except "delta.d": enter a "0" there. When finished, press an extra [Enter] to return to the Inputs Menu.

  - Enter the Seed used in randomization (between 1 and 1000).

  - You can not change the Power Market Structure Type input. This can be done from the CONTROL Menu.

  - Enter a value between 0 and 1 for Alpha.

- Press [MULTIPLIERS..] to enter Flag, plant capacity multipliers and demand multipliers.

- Press [FINISHED] to return to the previous menu.

-- Press [CONTROL..] to enter scenario identifier code (ID), scenario description, and other variables.

- Enter up to seven characters (letters or numbers, minimum one character), for Scenario ID Code.

- You will then be prompted for scenario description. Only the first 31 characters typed are accepted.

- Enter the Power Market Structure Type.

- Enter the Grid Fixed and Overhead Costs.

- Enter 1 or 0 depending on whether "Shadow Price" calculations are required.

-- Press [GENCO..] to assign Company Names to Company Numbers and Overhead Costs for each Company Number. Then assign Company Numbers to each plant.

-- Press [OTHERCOSTS...] to assign Fixed Plant Costs per Annum and Zonal Cost and Price values.

-- Press [FINISHED] to return to the previous menu.

o If necessary, you may revisit any of the above Input entry screens. When finished, press [FINISHED] to return to the Main Menu.

Run Optimization

o From the Main Menu, press [PROCESSING..], and the Processing Menu and accompanying screen appear. Make your selections and Enter.

Inspect Results

o From the Main Menu, press [OUTPUTS..], and the Outputs Menu and accompanying screen appear.

-- Press [CASHFLOWS 1] to view a summary of cash flows by company, presenting optimization results by period and in total. The list extends beyond

the visible screen: use the arrow keys to reach all companies. To get back to the Main Menu you have to press [Alt M].

-- Get back to the Output Menu and Press [CASHFLOWS 2] to view a summary of cash flows by zonal pools, presenting optimization results by period and in total. To get back to the Main Menu you have to press [Alt M].

-- Get back to the Output Menu and,

- Press [AGGREGATE..] to save the REPOINP.WK3 and to retrieve the REPOAGGR.WK3.

- Press [DAY1..] to save the REPOINP.WK3 and to retrieve the REPO1.WK3 spreadsheet for Type Day 1 detailed results.

- Press [DAY2..] to save the REPOINP.WK3 and to retrieve the REPO2.WK3 spreadsheet for Type Day 2 detailed results.

- Press [DAY3..] to save the REPOINP.WK3 and to retrieve the REPO3.WK3 spreadsheet for Type Day 3 detailed results.

- Press [FINISHED] to get back to the Main Menu in REPOINP.WK3

-- Note that if you select [AGGREGATE..], [DAY1..], [DAY2..], or [DAY3..], the program will exit the REPOINP.WK3. To do printing or the reports in REPOINP.WK3 as described in the following section, you need to get back to REPOINP.WK3.

Print Results

o From the Main Menu press [REPORTS..], and Reports Menu appears. First Set Up your printer parameters by following the instruction. Then make you selections and Enter.

Note: The page size must be appropriately set using Lotus 1-2-3 commands before using the print function of the model for the first time.

Update

o Whenever the user plans to change or add new (i) plants and/or (ii) Companies, the user must do the following steps:

- Change or add the new companies and plants in the input area

- Press [UPDATE..] in the main menu to reflect the changes to all the output areas.

The user must be very careful in adding new zones or regions. Some of these new additions might require a change in the C program of the model. But changing the names of companies or plants or adding new plants can be done easily by the user without changing the C program.

Save Results

Currently, you may save the entire spreadsheet with its results, under a name of your choosing (based on Scenario ID), or any other name using standard Lotus 1-2-3 methods.

o To save the file, select [SAVE..] in the Main menu. Currently, you can save the entire spreadsheet with its results, under its given name.

Exit to DOS

o When finished with a session, from the Main Menu press [EXIT..], and then [DOS].

While in the REPOAGGR.WK3 spreadsheet:

o In the Main Menu of this spreadsheet, first press [FETCH..] to import the relevant ASCII files generated by the optimization program.

o In case the name of companies were changed, press [UPDATE..] to update the names in the REPOAGGR.WK3.

o Press [OUTPUTS..] to get into the Output Menu.

  -- Press [CASHFLOW 1] to view a summary of cash flows by company. To get back to the Main Menu, press [Alt M].

  -- Get Back to the Output Menu, and Press [CASHFLOW 2] to view a summary of cash flows by zonal pools. Press [Alt M] to get back to the Main Menu.

  -- Get Back to the Output Menu, and Press [AGGREGATE] to view aggregate physical output and actual utilization values for plants and lines, and the Shadow Prices for constraints. Press [Alt M] to get back to the Main Menu.

-- Get Back to the Output Menu, and Press [DETAILED..] to view a detailed aggregate view of company by company financial and physical results for the year. Press [Alt M] to get back to the Main Menu.

-- Get Back to the Output Menu, and Press [OTHER..] to get to the Other Menu.

- Press [INPUTS..] to save the REPOAGGR.WK3 and to retrieve the REPOINP.WK3.

- Press [DAY1..] to save the REPOAGGR.WK3 and to retrieve the REPO1.WK3 spreadsheet for Type Day 1 detailed results.

- Press [DAY2..] to save the REPOAGGR.WK3 and to retrieve the REPO2.WK3 spreadsheet for Type Day 2 detailed results.

- Press [DAY3..] to save the REPOAGGR.WK3 and to retrieve the REPO3.WK3 spreadsheet for Type Day 3 detailed results.

- Press [FINISHED] to get back to the Main Menu in REPOAGGR.WK3.

o In the Main Menu of REPOAGGR.WK3, press [REPORTS..] to print the selected sections of the REPOAGGR.WK3 spreadsheet.

o Press [SAVE..] to save the REPOAGGR.WK3 in the hard-disk.

o Press [EXIT..] to exit the program completely.

<u>While in the REPO1.WK3 (or similarly in REPO2.WK3 and REPO3.WK3) spreadsheet:</u>

o In the Main Menu of this spreadsheet, first press [FETCH..] to import the relevant ASCII files generated by the optimization program.

o In case the name of companies were changed, press [UPDATE..] to update the names in the REPO1.WK3.

o Press [OUTPUTS..] to get into the Output Menu.

-- Press [CASHFLOW 1] to view a summary of cash flows by company. To get back to the Main Menu, press [Alt M].

-- Get Back to the Output Menu, and Press [CASHFLOW 2] to view a summary of cash flows by zonal pools. Press [Alt M] to get back to the Main Menu.

-- Get Back to the Output Menu, and Press [PHYSICAL] to view aggregate physical output for each period of the day. Press [Alt M] to get back to the Main Menu.

-- Get Back to the Output Menu, and Press [DETAILED..] to view a detailed plant by plant results for each period. Press [Alt M] to get back to the Main Menu.

- Get Back to the Output Menu, and Press [OTHER..] to get to Other Menu.

  - Press [INPUTS..] to save the REPO1.WK3 and to retrieve the REPOINP.WK3.

  - Press [DAY2..] to save the REPO1.WK3 and to retrieve the REPO2.WK3 spreadsheet for Type Day 2 detailed results.

  - Press [DAY3..] to save the REPO1.WK3 and to retrieve the REPO3.WK3 spreadsheet for Type Day 3 detailed results.

  - Press [AGGREGATE..] to save the REPO1.WK3 and to retrieve the REPOAGGR.WK3 spreadsheet for detailed aggregate results.

  - Press [FINISHED] to get back to the Main Menu in REPOAGGR.WK3.

-- In the Main Menu of REPO1.WK3, press [REPORTS..] to print the selected sections of the REPO1.WK3 spreadsheet.

-- Press [SAVE..] to save the REPO1.WK3 in the hard-disk.

-- Press [EXIT..] to exit the program completely.

o The menus in REPO2.WK3 and REPO3.WK3 are similar to ones in REPO1.WK3.

REPOINP.WK3 MAIN Menus

MAIN Menu

INPUTS..	Enter Plant, Line, Demand, and other inputs
PROCESSING..	Select time periods to run, and run them
OUTPUTS..	Examine outputs after optimization

REPORTS..	Print inputs and outputs reports
UPDATE..	Update the changes made to region codes, plant names or company names in the input area to all the output areas.
SAVE..	Save the current spreadsheet
EXIT..	Return to DOS (with option to save before exiting)

INPUTS.. Menu

DAY1..	Input menu for Type Day 1
DAY2..	Input menu for Type Day 2
DAY3..	Input menu for Type Day 3
CONTROL..	Scenario name input
GENCO..	Input Generating Company Names, Overhead Costs, and Assignment of Company Names to Plants
OTHERCOSTS..	Input Plant Fixed Costs, and Zonal Prices
FINISHED	Return to MAIN menu

DAY1.. Menu

BIDS..	Input plant capacity, bid prices and contracts
LINES..	Input lines capacity and availability
DEMAND..	Input demand by time period, and also duration of time periods
SCENARIO..	Provide scenario specific variables and input the stochastic parameters
MULTIPLIERS..	Input Plant Availability Factors (period by period) and Demand Multiplier values.
FINISHED	Return to MAIN menu

PROCESSING.. Menu

ALL	Run the optimization for all 9 periods
MAIN	Return to the MAIN menu without processing

OUTPUTS.. Menu

CASHFLOWS 1	View summary of cash flows by company
CASHFLOWS 2	View summary of cash flows by zone
AGGREGATE	Retrieve REPOAGGR.WK3 spreadsheet
DAY1	Retrieve REPO1.WK3 spreadsheet
DAY2	Retrieve REPO2.WK3 spreadsheet
DAY3	Retrieve REPO3.WK3 spreadsheet
FINISHED	Return to MAIN menu

REPORTS.. Menu

SET UP..	Set Up your printer parameters
DAY1	Print Report of DAY 1
DAY2	Print Report of DAY 2
DAY3	Print Report of DAY 3
CASHFLOW	Print Report of Aggregate Cash Flows
ALL	Print All Inputs and Aggregate Cash Flow Reports
FINISHED	Return to MAIN menu

UPDATE.. MENU

--	Update Plant Names/ Regions info in Spreadsheet

SAVE.. Menu

--	Save the spreadsheet

EXIT.. Menu

DOS	Exit to DOS
MAIN	Don't exit. Return to main menu
RESERVED	For development and maintenance use only

III. USER CAUTIONS

It is important to adhere to certain fixed rules in order to maintain the performance of the model.

- Be sure NOT to delete, add, or move any row or column in the spreadsheet. Data can always be moved to another spreadsheet and manipulated there.

- Be sure NOT to enter "garbage inputs" e.g. entering characters in places where integers are required. This would result in an improper running of the model.

- Sometimes the model may not run properly if very high input values have been given. It would then help to increase the Column Width of the corresponding column using the *Lotus 1-2-3* command.

- Do NOT tamper with any of the "*.PRN" files which accompany the C code in the directory C:\REPO.

- If the print macros of the model are not functioning properly, check that the page size of the printer has been appropriately set using the *Lotus 1-2-3* commands.

- Do not use comma-based formatting for numbers, otherwise, the optimization program will crash. Use only decimal based number formats.

IV. INSTALLING THE REPMOFF

REPMOFF runs on any 386 or 486 DOS-based machine with at least 4 MB of RAM and which can run Lotus 1-2-3 release 3.4 for DOS. All files are contained in one 3.5" installation diskette in a compressed mode. The Lotus input spreadsheet is named REPOINP.WK3. The Lotus output spreadsheets are REPO1.WK3, REPO2.WK3, REPO3.WK3 and REPOAGGR.WK3. The Install procedure of the model will install all the C files and all the spreadsheets in the directory C:\REPO.

Installation Steps

1. Enter DOS:

   - Quit windows or any other program running on the PC and enter the DOS command mode.

   - Insert the Installation Diskette in the appropriate floppy drive of the PC. This may be either drive A or drive B depending upon the configuration of the PC.

   - At the DOS prompt type the command "A:" or "B:" to switch to the drive which has the installation diskette.

2. Install:

   - Enter the command "INSTALL".
     On typing this command, the following message will be displayed on the screen:

     "ALL FILES FOR REPMOFF WILL BE LOADED IN DIRECTORY C:\REPO"

     If the directory does not exist, the program will create one.

3. Wait for Installation:

   The installation procedure will take a few minutes and upon completion the following message will be displayed on the screen.

   "INSTALLATION SUCCESSFULLY COMPLETED"

APPENDIX C

Terminologies Used in the Model

1. INPUTS

The model assumes three day types to model over any given time horizon (say, a season or a year). Thus, the entire year is modelled using three typical days. The user can input data for each of the three day types. Each day type is further subdivided into nine periods. The user can define the number of hours in each period so that the total number of hours across the nine periods total to twenty four.

Bid Inputs

- Unit Variable Costs: Variable costs in R/MWh for each generating plant.
- Bid Capacity: Available capacity in MW for each generating plant.
- Settlement Price: Settlement price is the least price in R/MWh that each generating plant would settle to sell its energy under any market structure.
- Dispatch Price: Dispatch price in R/MWh is the price used by the model to perform a least cost dispatch. Usually, dispatch price is the same as settlement price, but under certain scenarios it might be desirable to have artificial dispatch prices to force a particular dispatch behavior.
- Generator Availability Factor: This factor takes a value between 0 and 1 and is used as the multiplier to de-rate a plant's bid capacity.

Demand Inputs

- **Hours Per Period:** The number of hours for each of the nine periods of the day.
- **Demand:** Demand in MW for each zone in each period of each day. The nine periods in a day can be used to enter a load duration curve for the day.

Line Inputs

- Line Capacity: Transmission line capacity in MW between each pair of zones. The model allows bi-directional flow across lines and also bi-directional line capacities.

Financial Inputs

- Line Maintenance Costs: These are the variable costs to the national grid of maintaining transmission lines. These costs are entered in Rubles for each period of each day.

- Fixed and Overhead Costs for the Grid: These are fixed and overhead costs in Rubles per day for the national grid.

- Zonal Pool Fixed and OH Costs: These are fixed and overhead costs in Rubles per day for each zonal pool.

- Zonal Distribution Company Fixed and OH Costs: These are fixed and overhead costs in Rubles per day for each zonal distribution company. The model currently assumes one distribution company per zone.

- Fixed Costs for Generating Plants: These are fixed costs in Rubles per day for each generating plant.

- Overhead Costs for Generating Companies: These are overhead costs in Rubles per day for each generating company. Each generating company may own a number of plants. These overhead costs are the aggregate overhead costs for the generating company owning a number of plants.

- Zonal Wholesale Price: Wholesale price in R/MWh for each zone. Zonal wholesale price is charged by each zonal pool to its respective zonal distribution company.

- Zonal Grid Tariff: Grid tariff in R/MWh for each zone. Zonal grid tariff is charged by the national grid to respective zonal distribution companies.

- Zonal Retail Price: Retail price in R/MWh for each zone. Zonal retail price is charged by each zonal distribution company to the customers in its zone.

Generating Company Inputs

- Company Names: The name of each generating company assigned to a specific company number or company id e.g. company number 1 could be given the name "Electric Co1".

- Assign Company Number to Plants: This is used to input the ownership structure for the generating plants by assigning a company number to each generating plant.

Multiplier Inputs

- Plant Capacity Multipliers: These multipliers are factors by which the bid capacity of plants is scaled for each period of the run.

- Demand Multiplier: The factor by which the demand for each period within a day is scaled.

Stochastic and Other Inputs

- Pi: Probability that a generating plant will have its full de-rated bid capacity available for production. De-rated bid capacity is the bid capacity times the generator availability factor.

- Sigma.pi: Multiplier (between 0 and 1) by which the de-rated bid capacity of a plant gets further scaled to result in available capacity.

- Lambda: Probability that a transmission link is fully available.

- Line.d: Multiplier (between 0 and 1) by which a transmission line's capacity is scaled to result in available capacity.

- Delta.d: Probability that demand will be less than projected.

- Sigma.d: Multiplier (between 0 and 1) to scale demand for the lower demand case.

- Delta.u: 1 - (Probability that demand will be higher than projected).

- Sigma.u: Multiplier (must be > = 1) to scale demand for the higher demand case.

- Seed: Integer value between 1 and 1000 used by the random number generator of the model. Different seed values generate different series of random numbers. Same seed values will always generate the same series of random numbers at all times.

- Alpha: Multiplier (between 0 and 1) to scale the adjusted transmission line capacity (adjusted for any probabilistic break downs) and result in net transfer capacity across each line.

- Num Days: The number of days represented by each day type.

- Loss Factor: Loss factor (between 0 and 1) is the linear power loss factor across each line. Thus, a loss factor of 0.05 implies that approximately 5 per cent of power gets lost in transmission across a line.

Control Inputs

These are inputs which are common for all the day types.

- Scenario Id: The identification for each scenario can be up to 8 characters.

- Scenario.Desc: The description for the scenario run by the model. Scenario Id and scenario description are useful for identifying various runs made by the model.

- Market Structure: "1" for type A, "2" for type B, and "3" for type C market structure.

- Shadow Price?: "1" to compute the shadow prices for generating plants and transmission lines; "0" otherwise.

2. OUTPUTS FOR EACH DAY TYPE

Detailed Outputs

These are outputs for each generating plant for each period of each day.

- Variable Costs: Variable costs in R for each generating plant computed by multiplying the total generation (MWh) of the plant in a given period by its unit variable cost (R/MWh).

- Settlement Price: Original settlement price (R/MWh) that was input by the user.

- Dispatch Price: Actual dispatch price (R/MWh).

- Adjusted Capacity: This is the available capacity in MW of each generating plant for each period of the day adjusted for any de-rating and any stochastic scaling of capacity.

- Unconstr Sch. MW: This output is meaningful for only Type A market structure. It is the unconstrained scheduled MW for each generating plant computed by the unconstrained merit order under bid price based uniform system marginal price market structure (Type A).

- Constr Sch. MW: This is the final scheduled generation (in MW) for each generating plant as produced by the dispatch algorithm of the model.

- Adjusted Settlement Price: Adjusted settlement price is the actual settlement price used in computing payments made by the zonal pool to the generating plants in its zone. Adjusted settlement price may or may not be the same as the original settlement price input by the user depending upon the market structure e.g. under Type A market structure the adjusted settlement price is SMP for all plants in the unconstrained merit order and is bid price for all other plants. Under Type B market structure the adjusted settlement price for a plant is the ZMP of its zone.

- ZMP: Zonal marginal price (in R/MWh) for each zone.

- Energy Payments: These are payments made by the zonal pool to the generating plants for the purchase of energy. Energy payments are usually the total payments made by the zonal pool to the generating plants except in Type A market structure. Under Type A market structure all energy payments are payments made based on SMP. Any payments made in excess of SMP based payments are known as Uplift payments.

- Uplift Payments: Uplift payments are payments made by zonal pools to generating plants under Type A market structure over and above SMP based energy payments. Uplift payments are zero for other market structures. The uplift payment component arises for constrained-on plants whose bid price is greater than SMP.

- Total Payments: Total payments received by each generating plant. This is the sum of energy and uplift payments.

Physical Outputs

- Realized Plant Capacities: These are the realized plant capacities in MW for each period of the day, adjusted for any de-rating and any stochastic scaling.

- Realized Demand: These are demand values in MW for each zone in each period of the day adjusted for any stochastic variations.

- Actual Demand Met: This is the actual demand met (in MW) in each zone for each period of the day.

- Shortage: This is the shortage in MW for each zone in each period of the day.

- SMP: This is the system marginal price in R/MWh for each period of the day. SMP is meaningful only for Type A market structure.

- Realized Line Capacities: These are the final realized line capacities in MW for each period of the day adjusted for any stochastic scaling.

- Actual Line Transfer: This is the actual flow in MW across each transmission line for each period of the day.

CashFlow Outputs

- Income Statement for the National Grid: Income statement for the day.

- Income Statement for the Generating Companies: Income statements for the day.

- Income Statement for the Zonal Pools: Income Statement for the day.

- Income Statement for the Zonal Distribution Company: Income Statement for the day.

- Benchmark Zonal Wholesale Prices: Daily benchmark zonal wholesale price in R/MWh for each zone. The benchmark zonal wholesale price for a zonal pool is the break-even price for that pool. It is the price at which the zonal pool can sell its energy to the distribution companies so as to recover all its costs, i.e. it is the price at which *"revenue from sale in wholesale market + export earnings = cost of buying power from generating plants + import costs + fixed and overhead costs"*. The benchmark price is thus the least price that a zonal pool can charge to recover all its costs.

- Average System Wholesale Price: Daily benchmark system wholesale price in R/MWh for the entire system. This price is computed by dividing (the total payments made to the generating plants by all the zonal pools plus the total fixed and overhead costs of all zonal pools) by (the total consumption of power in the entire system). It is the least average wholesale price that each zonal pool can charge so that the total costs for all the pools combined is recovered.

- Benchmark Zonal Retail Price 1: Daily benchmark zonal retail price 1 in R/MWh for each zone. Benchmark retail price 1 is the break-even price at which a zonal distribution company can recover all its costs *assuming that the distribution company buys power in the wholesale market at benchmark zonal wholesale prices.* Thus, this price is the least price that a zonal distribution company can charge to recover all its costs. The costs to a distribution company are the costs of buying power in the wholesale market, the grid tariff payments made to the national grid and the fixed and overhead costs.

- Benchmark Zonal Retail Price 2: Daily benchmark zonal retail price 2 in R/MWh for each zone. Benchmark retail price 2 is the break-even price at which a zonal distribution company can recover all its costs *assuming that the distribution company buys power in the wholesale market at the wholesale prices input by the user.* Thus, this price is the least price that a zonal distribution company can charge to recover all its costs. The costs to a distribution company are the costs of buying power in the wholesale market, the grid tariff payments made to the national grid and the fixed and overhead costs.

- Average System Retail Price 1: Daily benchmark system retail price 1 in R/MWh for the entire system. Average system retail price 1 is the least average retail price that each zonal distribution company can charge so as to recover the total costs for all the distribution companies combined *assuming that the distribution company buys power in the wholesale market at benchmark wholesale prices.*

- Average System Retail Price 2: Daily benchmark system retail price 2 in R/MWh for the entire system. Average system retail price 2 is the least average retail price that each zonal distribution company can charge so as to recover the total costs for all the distribution companies combined *assuming that the distribution company buys power in the wholesale market at wholesale prices input by the user.*

3. AGGREGATE OUTPUTS FOR THE ENTIRE YEAR

<u>Aggregate Detailed Outputs</u>

- **Variable Costs:** Yearly variable costs for each generating plant.

- Total Generation: Yearly total generation in MWh for each generating plant.

- Energy Earnings: Yearly energy earnings for each generating plant.

- Uplift Earnings: Yearly uplift earnings for each generating plant.

- Aggregate Fixed Costs: Yearly fixed costs for each generating plant.
- Income: Yearly income for each generating plant.

Aggregate Physical Outputs

- Consumption: Yearly consumption of energy in MWh for each zone.
- Generation: Yearly generation of energy in MWh for each zone.
- Shortage: Yearly shortage of energy in MWh for each zone.
- Adjusted Capacity: Adjusted generation capacity in MW for each zone for each day type.
- Imports: Yearly import of energy in MWh for each zone.
- Exports: Yearly export of energy in MWh for each zone.
- Line Activity: Number of hours in the year that a line limit is used.
- Line Utilization: Line limit utilization in percentage. This is computed by dividing line activity (in hours) by the total number of hours in a year.
- Line Shadow Price: Line shadow price in R/MW is the *reduction* in the total payments received by all generating plants in a year due to 1 MW increase in the capacity of a line.
- C-On Plant Usage: This is the number of hours a plant is used in a year as a constrained-on plant under Type A market structure.
- Total Plant Usage: This is the total plant usage in hours for the entire year.
- Total Plant Utilization: This is the total plant utilization in percentage computed by dividing the total number of hours a plant is used by the total number of hours in a year.
- Plant Shadow Price: Plant shadow price in R/MW is the *reduction* in the total payments received by all generating plants in a year due to 1 MW increase in the capacity of a plant.

CashFlow Outputs

- Income Statement for the National Grid: Income statement for the year.

- Income Statement for the Generating Companies: Income statements for the year.

- Income Statement for the Zonal Pools: Income Statement for the year.

- Income Statement for the Zonal Distribution Company: Income Statement for the year.

- Benchmark Zonal Wholesale Prices: Yearly benchmark zonal wholesale price in R/MWh for each zone. The benchmark zonal wholesale price for a zonal pool is the break-even price for that pool. It is the price at which the zonal pool can sell its energy to the distribution companies so as to recover all its costs i.e. it is the price at which *"revenue from sale in wholesale market + export earnings = cost of buying power from generating plants + import costs + fixed and overhead costs"*. The benchmark price is thus the least price that a zonal pool can charge to recover all its costs.

- Average System Wholesale Price: Yearly benchmark system wholesale price in R/MWh for the entire system. This price is computed by dividing (the total payments made to the generating plants by all the zonal pools plus the total fixed and overhead costs of all zonal pools) by the total consumption of power in the entire system. It is the least average wholesale price that each zonal pool can charge so that the total costs for all the pools combined is recovered.

- Benchmark Zonal Retail Price 1: Yearly benchmark zonal retail price 1 in R/MWh for each zone. Benchmark retail price 1 is the break-even price at which a zonal distribution company can recover all its costs *assuming that the distribution company buys power in the wholesale market at benchmark zonal wholesale prices*. Thus, this price is the least price that a zonal distribution company can charge to recover all its costs. The costs to a distribution company are the costs of buying power in the wholesale market, the grid tariff payments made to the national grid and the fixed and overhead costs.

- Benchmark Zonal Retail Price 2: Yearly benchmark zonal retail price 2 in R/MWh for each zone. Benchmark retail price 2 is the break-even price at which a zonal distribution company can recover all its costs *assuming that the distribution company buys power in the wholesale market at the wholesale prices input by the user*. Thus, this price is the least price that a zonal distribution company can charge to recover all its costs. The costs to a distribution company are the costs of buying power in the wholesale market, the grid tariff payments made to the national grid and the fixed and overhead costs.

- Average System Retail Price 1: Yearly benchmark system retail price 1 in R/MWh for the entire system. Average system retail price 1 is the least average retail price that each zonal distribution company can charge so as to recover the total costs for all the distribution companies combined *assuming that the distribution company buys power in the wholesale market at benchmark wholesale prices.*

- Average System Retail Price 2: Yearly benchmark system retail price 2 in R/MWh for the entire system. Average system retail price 2 is the least average retail price that each zonal distribution company can charge so as to recover the total costs for all the distribution companies combined *assuming that the distribution company buys power in the wholesale market at wholesale prices input by the user.*

APPENDIX D

Data Input to the Framework

Available Data

The data and results provided in the later appendices are preliminary and for demonstration only, and they are not meant to be used to draw any conclusions about investment alternatives.

a) Model of electric transmission system in Russia aggregated at 8 zone levels:

1 North West
2 Center
3 North Caucus
4 Mid Volga
5 Ural
6 Siberia
7 Tyumen
8 Far East

b) Model of generation aggregated as eight plant-types in each zone:

1 NPP: Nuclear
2 HPP: Hydro
3 CPP-A: Condensed Steam (Gas, Oil, Steam)
4 CPP-B: Condensed Steam (Gas, Steam)
5 CPP-C: Condensed Steam (Coal)
6 CHP-A: Combined Heat/Power (Gas, Oil, Steam)
7 CHP-B: Combined Heat/Power (Gas, Steam)
8 CHP-C: Combined Heat/Power (Coal)
9 GT: Gas Turbine

c) Bi-directional transmission capacity limits between zones.

d) Plant-type capacities in each zone.

e) Plant-type heat rates in each zone.

f) Plant-type fuel cost in each zone.

g) Plant-type minimum yearly hours of operation in each zone.

h) Plant-type maximum yearly hours of operation in each zone.

i) Monthly demand levels in each zone.

j) Load shape for a peak winter day (the only day-type used in ERI's integrated resource planning program).

k) Additional information on the peculiarities of dispatch for hydro and combined heat/power plants.

Data Sources

The following are the data sources for the preliminary data set for 1992 used by the model:

- Demand: Data taken from tables provided by the Working Group 5 "Strategy and Integration", March 1994.
- Generator Capacities: Data taken from tables provided by the Working Group 5 "Strategy and Integration", March 1994.
- Generator Variable Costs: Data provided directly by ERI.
- Generator Availability Factors: Data provided directly by ERI.
- Transmission Line Capacities: Data provided directly by ERI.
- Zonal Hourly Load Curves (demand multipliers): Data provided in ERI computer output sheet.
- Zonal Investments: Data provided in ERI computer output sheet.

Data Input Sheets

The following are the data input sheets used by the model.

Scenario: ERI1995
ERI 1995 Scenario, 07/19/94

(REPMOFF)
RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Input Documentation

C:\REPO\REPOINP.WK3
21 Jul 94 13:46

DAY 1

(Note: Total Day In the Year may not be 365

Plant No.	Zone Code	Company Name	Plant Name	Plant Variable Cost (R/MWh)	Bid Capacity (MW)	Settlement Price (R/MWh)	Dispatch Price (R/MWh)	Plant Availability Factor (betw 0 & 1)	Plant Fixed Costs per Day (Rubles/Day)
0	NWEST	NWEnergo	HPP	0.00	2900.0	10.00	10.00	1.00	0
1	NWEST	MINATOM	NPP	0.00	5800.0	10.00	10.00	1.00	0
2	NWEST	NWEnergo	CHP-A	13.53	2500.0	23.53	23.53	1.00	0
3	NWEST	NWEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
4	NWEST	NWEnergo	CHP-C	13.55	1900.0	23.55	23.55	1.00	0
5	NWEST	NWEnergo	CPP-A	21.54	1200.0	31.54	31.54	1.00	0
6	NWEST	NWEnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
7	NWEST	NWEnergo	GT	0.00	0.0	0.00	0.00	1.00	0
8	NWEST	NWEnergo	CPP-C	0.00	200.0	10.00	10.00	1.00	0
9	NWEST	NWEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
10	NWEST	NWEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
11	NWEST	NWEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
12	NWEST	NWEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
13	NWEST	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
14	NWEST	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
15	NWEST	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
16	CENTER	CNEnergo	HPP	0.00	4900.0	10.00	10.00	1.00	0
17	CENTER	MINATOM	NPP	0.00	12800.0	10.00	10.00	1.00	0
18	CENTER	CNEnergo	CHP-A	15.51	14600.0	25.51	25.51	1.00	0
19	CENTER	CNEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
20	CENTER	CNEnergo	CHP-C	12.65	8200.0	22.65	22.65	1.00	0
21	CENTER	CNEnergo	CPP-A	20.23	7000.0	30.23	30.23	1.00	0
22	CENTER	CNEnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
23	CENTER	CNEnergo	GT	11.78	500.0	21.78	21.78	1.00	0
24	CENTER	CNEnergo	CPP-C	16.83	3300.0	26.83	26.83	1.00	0
25	CENTER	CNEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
26	CENTER	CNEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
27	CENTER	CNEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
28	CENTER	CNEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
29	CENTER	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
30	CENTER	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
31	CENTER	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
32	NCAUC	NCEnergo	HPP	0.00	3000.0	10.00	10.00	1.00	0
33	NCAUC	MINATOM	NPP	0.00	0.0	0.00	0.00	1.00	0
34	NCAUC	NCEnergo	CHP-A	18.99	1900.0	28.99	28.99	1.00	0
35	NCAUC	NCEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
36	NCAUC	NCEnergo	CHP-C	23.54	100.0	33.54	33.54	1.00	0
37	NCAUC	NCEnergo	CPP-A	22.00	3900.0	32.00	32.00	1.00	0
38	NCAUC	NCEnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
39	NCAUC	NCEnergo	GT	0.00	0.0	0.00	0.00	1.00	0
40	NCAUC	NCEnergo	CPP-C	20.61	600.0	30.61	30.61	1.00	0
41	NCAUC	NCEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
42	NCAUC	NCEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
43	NCAUC	NCEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
44	NCAUC	NCEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
45	NCAUC	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
46	NCAUC	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
47	NCAUC	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
48	MVOLGA	MVEnergo	HPP	0.00	6200.0	10.00	10.00	1.00	0
49	MVOLGA	MINATOM	NPP	0.00	4000.0	10.00	10.00	1.00	0
50	MVOLGA	MVEnergo	CHP-A	15.30	9500.0	25.30	25.30	1.00	0
51	MVOLGA	MVEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
52	MVOLGA	MVEnergo	CHP-C	10.60	1400.0	20.60	20.60	1.00	0
53	MVOLGA	MVEnergo	CPP-A	20.42	1300.0	30.42	30.42	1.00	0
54	MVOLGA	MVEnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
55	MVOLGA	MVEnergo	GT	0.00	0.0	0.00	0.00	1.00	0
56	MVOLGA	MVEnergo	CPP-C	0.00	0.0	0.00	0.00	1.00	0
57	MVOLGA	MVEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
58	MVOLGA	MVEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
59	MVOLGA	MVEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
60	MVOLGA	MVEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
61	MVOLGA	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
62	MVOLGA	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
63	MVOLGA	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
64	URALS	UREnergo	HPP	0.00	1800.0	10.00	10.00	1.00	0
65	URALS	MINATOM	NPP	0.00	600.0	10.00	10.00	1.00	0

Scenario: ERI1996
ERI 1996 Scenario, 07/19/94

(REPMOFF)
RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Input Documentation

21 Jul 94 13:46

DAY 1

(Note: Total Days in the Year may not be 365 !)

Plant No.	Zone Code	Company Name	Plant Name	Plant Variable Cost (R/MWh)	Bid Capacity (MW)	Settlement Price (R/MWh)	Dispatch Price (R/MWh)	Plant Availability Factor (betw 0 & 1)	Plant Fixed Costs per Day (Rubles/Day)
66	URALS	UREnergo	CHP-A	13.74	5200.0	23.74	23.74	1.00	0
67	URALS	UREnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
68	URALS	UREnergo	CHP-C	9.64	6600.0	19.64	19.64	1.00	0
69	URALS	UREnergo	CPP-A	17.64	7500.0	27.64	27.64	1.00	0
70	URALS	UREnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
71	URALS	UREnergo	GT	0.00	0.0	0.00	0.00	1.00	0
72	URALS	UREnergo	CPP-C	11.43	5200.0	21.43	21.43	1.00	0
73	URALS	UREnergo	Other	0.00	0.0	0.00	0.00	1.00	0
74	URALS	UREnergo	Other	0.00	0.0	0.00	0.00	1.00	0
75	URALS	UREnergo	Other	0.00	0.0	0.00	0.00	1.00	0
76	URALS	UREnergo	Other	0.00	0.0	0.00	0.00	1.00	0
77	URALS	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
78	URALS	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
79	URALS	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
80	SIBERIA	SIEnergo	HPP	0.00	22300.0	10.00	10.00	1.00	0
81	SIBERIA	MINATOM	NPP	0.00	0.0	0.00	0.00	1.00	0
82	SIBERIA	SIEnergo	CHP-A	0.00	0.0	0.00	0.00	1.00	0
83	SIBERIA	SIEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
84	SIBERIA	SIEnergo	CHP-C	5.03	14300.0	15.03	15.03	1.00	0
85	SIBERIA	SIEnergo	CPP-A	0.00	0.0	0.00	10.00	1.00	0
86	SIBERIA	SIEnergo	CPP-B	0.00	0.0	0.00	10.00	1.00	0
87	SIBERIA	SIEnergo	GT	0.00	0.0	0.00	10.00	1.00	0
88	SIBERIA	SIEnergo	CPP-C	6.60	4600.0	16.60	16.60	1.00	0
89	SIBERIA	SIEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
90	SIBERIA	SIEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
91	SIBERIA	SIEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
92	SIBERIA	SIEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
93	SIBERIA	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
94	SIBERIA	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
95	SIBERIA	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
96	TYUMEN	TYEnergo	HPP	0.00	0.0	0.00	0.00	1.00	0
97	TYUMEN	MINATOM	NPP	0.00	0.0	0.00	0.00	1.00	0
98	TYUMEN	TYEnergo	CHP-A	12.68	1700.0	22.68	22.68	1.00	0
99	TYUMEN	TYEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
100	TYUMEN	TYEnergo	CHP-C	5.05	8000.0	15.05	15.05	1.00	0
101	TYUMEN	TYEnergo	CPP-A	0.00	0.0	0.00	0.00	1.00	0
102	TYUMEN	TYEnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
103	TYUMEN	TYEnergo	GT	0.00	0.0	0.00	0.00	1.00	0
104	TYUMEN	TYEnergo	CPP-C	0.00	0.0	0.00	0.00	1.00	0
105	TYUMEN	TYEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
106	TYUMEN	TYEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
107	TYUMEN	TYEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
108	TYUMEN	TYEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
109	TYUMEN	MINATOM	LM	0.00	10000.0	0.00	500.00	1.00	0
110	TYUMEN	MINATOM	LM	0.00	10000.0	0.00	500.00	1.00	0
111	TYUMEN	MINATOM	LM	0.00	10000.0	0.00	500.00	1.00	0
112	FAREAST	FEEnergo	HPP	0.00	1300.0	0.00	10.00	1.00	0
113	FAREAST	MINATOM	NPP	0.00	0.0	0.00	0.00	1.00	0
114	FAREAST	FEEnergo	CHP-A	0.00	0.0	0.00	0.00	1.00	0
115	FAREAST	FEEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
116	FAREAST	FEEnergo	CHP-C	15.19	2900.0	25.19	25.19	1.00	0
117	FAREAST	FEEnergo	CPP-A	0.00	0.0	0.00	0.00	1.00	0
118	FAREAST	FEEnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
119	FAREAST	FEEnergo	GT	0.00	0.0	0.00	0.00	1.00	0
120	FAREAST	FEEnergo	CPP-C	23.02	2700.0	33.02	33.02	1.00	0
121	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
122	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
123	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
124	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
125	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
126	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
127	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
128	FAREAST	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
129	FAREAST	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
130	FAREAST	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
			TOTAL		422,400				

Scenario: ERI1995
ERI 1995 Scenario, 07/19/94

(REPMOFF)
RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Inputs Documentation

C:\REP\REP\REP.WK3
21 Jul 94 13:46

1. Enter hours per period, then press enter.
2. Enter expected demand by region, then press "enter" key when finished.

DAY 1

Assign Hours per period:	3	3	3	3	3	3	3	3	0
For all Periods Input Day's Peak Demand (MW):	Period 1	Period 2	Period 3	Period 4	Period 5	Period 6	Period 7	Period 8	Period 9
NWEST	14400	14400	14400	14400	14400	14400	14400	14400	0
CENTER	51200	51200	51200	51200	51200	51200	51200	51200	0
NCAUC	9500	9500	9500	9500	9500	9500	9500	9500	0
MVOLGA	22400	22400	22400	22400	22400	22400	22400	22400	0
URALS	26800	26800	26800	26800	26800	26800	26800	26800	0
SIBERIA	41200	41200	41200	41200	41200	41200	41200	41200	0
TYUMEN	9700	9700	9700	9700	9700	9700	9700	9700	0
FAREAST	6900	6900	6900	6900	6900	6900	6900	6900	0
Total	182,100	182,100	182,100	182,100	182,100	182,100	182,100	182,100	0

FINANCIAL & OTHER INPUTS

Note: YEARLY INVESTMENT Values should be divided by the SUM of Days in DAY1, DAY2, and DAY3

	Zonal Pool Fixed / Over-head Costs & Investment (Rubles/Day)	Zonal Distributio Fixed / Over-head Costs & Investment (Rubles/Day)	'Regulation' Zonal Wholesale Price (R/MWh)	'Regulation' Zonal Retail Price (R/MWh)	Zonal Grid Tariff (R/MWh)
NWEST	1226908	0	0.00	0.00	0.00
CENTER	4100896	0	0.00	0.00	0.00
NCAUC	2494367	0	0.00	0.00	0.00
MVOLGA	1265942	0	0.00	0.00	0.00
URALS	5985638	0	0.00	0.00	0.00
SIBERIA	4024792	0	0.00	0.00	0.00
TYUMEN	680350	0	0.00	0.00	0.00
FAREAST	3314675	0	0.00	0.00	0.00

LINE CAPACITIES (MW)

Zone	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1600	0	0	0	0	0	0
CENTER	1600	0	1000	4000	0	0	0	0
NCAUC	0	1000	0	0	0	0	0	0
MVOLGA	0	4000	0	0	3000	0	0	0
URALS	0	0	0	1800	0	3000	1000	0
SIBERIA	0	0	0	0	3000	0	0	0
TYUMEN	0	0	0	0	1000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

1. Scenario ID and description got from Control Inputs. DAY 1
2. Enter numdays, loss factor, stochastic variables, Other decision variables, then press "Enter" key when finished.

Scenario	ID	ERI1995	Used in filename. Maximum 7 letters or numbers, minimum 1.
	Desc.	ERI 1995 Scenario, 07/19/94	Describes scenario. Max 31 char.
Num Days		80	Number of days represented by DAY1
Loss Factor		0.05	Give a value between 0 and 1 for the linear line loss factor
Stochastic Inputs			
plants	pi	1.00	Probability plant will produce expected capacity
	sigma.p	0.50	Multiplier if it doesn't
lines	lambda	1.00	Probability line will be available
	line.d	1.00	Multiplier for lower line capacity
demand	delta.d	0.00	Probability demand will be lower than projected
	sigma.d	0.97	Multiplier for lower demand case (must be <= 1)
	delta.u	1.00	1 - (Probability demand will be higher than projected)
	sigma.u	1.03	Multiplier for higher demand case (must be >= 1)
seed		1	Give an integer value for seed; between 1 and 1000
Market Structure		3	"1" for Type A; "2" for B; "3" for C;
Alpha		1	Give a value between 0 and 1 for Alpha Net line capacity gets multiplied by alpha

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Scenario: ERI1995
ERI 1995 Scenario, 07/19/94

(REPMOFF)
RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Inputs Documentation

CVREPOVREPOHP WK 3
21 Jul 94 13:50

DAY 2

(Note: Total Day In the Year May not be 365

Plant No.	Zone Code	Co. Name	Plant Name	Plant Variable Cost (R/MWh)	Bid Capacity (MW)	Settlement Price (R/MWh)	Dispatch Price (R/MWh)	Plant Availability Factor (betw 0 & 1)	Plant Fixed Costs per Day (Rubles/Day)
0	NWEST	NWEnergo	HPP	0.00	2900.0	10.00	10.00	1.00	0
1	NWEST	MINATOM	NPP	0.00	5800.0	10.00	10.00	1.00	0
2	NWEST	NWEnergo	CHP-A	13.53	2500.0	23.53	23.53	1.00	0
3	NWEST	NWEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
4	NWEST	NWEnergo	CHP-C	13.55	1900.0	23.55	23.55	1.00	0
5	NWEST	NWEnergo	CPP-A	21.54	1200.0	31.54	31.54	1.00	0
6	NWEST	NWEnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
7	NWEST	NWEnergo	GT	0.00	0.0	0.00	0.00	1.00	0
8	NWEST	NWEnergo	CPP-C	0.00	200.0	10.00	10.00	1.00	0
9	NWEST	NWEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
10	NWEST	NWEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
11	NWEST	NWEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
12	NWEST	NWEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
13	NWEST	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
14	NWEST	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
15	NWEST	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
16	CENTER	CNEnergo	HPP	0.00	4900.0	10.00	10.00	1.00	0
17	CENTER	MINATOM	NPP	0.00	12600.0	10.00	10.00	1.00	0
18	CENTER	CNEnergo	CHP-A	15.51	14600.0	25.51	25.51	1.00	0
19	CENTER	CNEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
20	CENTER	CNEnergo	CHP-C	12.65	6200.0	22.65	22.65	1.00	0
21	CENTER	CNEnergo	CPP-A	20.23	7000.0	30.23	30.23	1.00	0
22	CENTER	CNEnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
23	CENTER	CNEnergo	GT	11.78	500.0	21.78	21.78	1.00	0
24	CENTER	CNEnergo	CPP-C	16.83	3300.0	26.83	26.83	1.00	0
25	CENTER	CNEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
26	CENTER	CNEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
27	CENTER	CNEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
28	CENTER	CNEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
29	CENTER	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
30	CENTER	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
31	CENTER	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
32	NCAUC	NCEnergo	HPP	0.00	3000.0	10.00	10.00	1.00	0
33	NCAUC	MINATOM	NPP	0.00	0.0	0.00	0.00	1.00	0
34	NCAUC	NCEnergo	CHP-A	18.99	1900.0	28.99	28.99	1.00	0
35	NCAUC	NCEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
36	NCAUC	NCEnergo	CHP-C	23.54	100.0	33.54	33.54	1.00	0
37	NCAUC	NCEnergo	CPP-A	22.00	3900.0	32.00	32.00	1.00	0
38	NCAUC	NCEnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
39	NCAUC	NCEnergo	GT	0.00	0.0	0.00	0.00	1.00	0
40	NCAUC	NCEnergo	CPP-C	20.61	600.0	30.61	30.61	1.00	0
41	NCAUC	NCEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
42	NCAUC	NCEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
43	NCAUC	NCEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
44	NCAUC	NCEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
45	NCAUC	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
46	NCAUC	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
47	NCAUC	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
48	MVOLGA	MVEnergo	HPP	0.00	6200.0	10.00	10.00	1.00	0
49	MVOLGA	MINATOM	NPP	0.00	4000.0	10.00	10.00	1.00	0
50	MVOLGA	MVEnergo	CHP-A	15.30	9500.0	25.30	25.30	1.00	0
51	MVOLGA	MVEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
52	MVOLGA	MVEnergo	CHP-C	10.60	1400.0	20.60	20.60	1.00	0
53	MVOLGA	MVEnergo	CPP-A	20.42	1300.0	30.42	30.42	1.00	0
54	MVOLGA	MVEnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
55	MVOLGA	MVEnergo	GT	0.00	0.0	0.00	0.00	1.00	0
56	MVOLGA	MVEnergo	CPP-C	0.00	0.0	0.00	0.00	1.00	0
57	MVOLGA	MVEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
58	MVOLGA	MVEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
59	MVOLGA	MVEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
60	MVOLGA	MVEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
61	MVOLGA	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
62	MVOLGA	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
63	MVOLGA	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
64	URALS	UREnergo	HPP	0.00	1800.0	10.00	10.00	1.00	0
65	URALS	MINATOM	NPP	0.00	600.0	10.00	10.00	1.00	0

Scenario: ERI1995
ERI 1995 Scenario, 07/19/94

DAY 2

(REPMOFF)
RUSSIA NELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Inputs Documentation

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21 Jul 94 1:50

(Note: Total Days in the Year May not be 365 !)

Plant No.	Zone Code	Co. Name	Plant Name	Plant Variable Cost (R/MWh)	Bid Capacity (MW)	Settlement Price (R/MWh)	Dispatch Price (R/MWh)	Plant Availability Factor (betw 0 & 1)	Plant Fixed Costs per Day (Rubles/Day)
66	URALS	UREnergo	CHP-A	13.74	5200.0	23.74	23.74	1.00	0
67	URALS	UREnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
68	URALS	UREnergo	CHP-C	9.84	9600.0	19.84	19.84	1.00	0
69	URALS	UREnergo	CPP-A	17.84	7600.0	27.84	27.84	1.00	0
70	URALS	UREnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
71	URALS	UREnergo	GT	0.00	0.0	0.00	0.00	1.00	0
72	URALS	UREnergo	CPP-C	11.43	5200.0	21.43	21.43	1.00	0
73	URALS	UREnergo	Other	0.00	0.0	0.00	0.00	1.00	0
74	URALS	UREnergo	Other	0.00	0.0	0.00	0.00	1.00	0
75	URALS	UREnergo	Other	0.00	0.0	0.00	0.00	1.00	0
76	URALS	UREnergo	Other	0.00	0.0	0.00	0.00	1.00	0
77	URALS	LM & Detail	LM	0.00	10000.0	0.00	500.00	1.00	0
78	URALS	LM & Detail	LM	0.00	10000.0	0.00	500.00	1.00	0
79	URALS	LM & Detail	LM	0.00	10000.0	0.00	500.00	1.00	0
80	SIBERIA	SIEnergo	NPP	0.00	22300.0	10.00	10.00	1.00	0
81	SIBERIA	MINATOM	NPP	0.00	0.0	0.00	0.00	1.00	0
82	SIBERIA	SIEnergo	CHP-A	0.00	0.0	0.00	0.00	1.00	0
83	SIBERIA	SIEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
84	SIBERIA	SIEnergo	CHP-C	5.03	14300.0	15.03	15.03	1.00	0
85	SIBERIA	SIEnergo	CPP-A	0.00	0.0	0.00	10.00	1.00	0
86	SIBERIA	SIEnergo	CPP-B	0.00	0.0	0.00	10.00	1.00	0
87	SIBERIA	SIEnergo	GT	0.00	0.0	0.00	10.00	1.00	0
88	SIBERIA	SIEnergo	CPP-C	6.60	4600.0	16.60	16.60	1.00	0
89	SIBERIA	SIEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
90	SIBERIA	SIEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
91	SIBERIA	SIEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
92	SIBERIA	SIEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
93	SIBERIA	LM & Detail	LM	0.00	10000.0	0.00	500.00	1.00	0
94	SIBERIA	LM & Detail	LM	0.00	10000.0	0.00	500.00	1.00	0
95	SIBERIA	LM & Detail	LM	0.00	10000.0	0.00	500.00	1.00	0
96	TYUMEN	TYEnergo	NPP	0.00	0.0	0.00	0.00	1.00	0
97	TYUMEN	MINATOM	NPP	0.00	0.0	0.00	0.00	1.00	0
98	TYUMEN	TYEnergo	CHP-A	12.69	1700.0	22.69	22.69	1.00	0
99	TYUMEN	TYEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
100	TYUMEN	TYEnergo	CHP-C	5.03	8000.0	15.03	15.03	1.00	0
101	TYUMEN	TYEnergo	CPP-A	0.00	0.0	0.00	0.00	1.00	0
102	TYUMEN	TYEnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
103	TYUMEN	TYEnergo	GT	0.00	0.0	0.00	0.00	1.00	0
104	TYUMEN	TYEnergo	CPP-C	0.00	0.0	0.00	0.00	1.00	0
105	TYUMEN	TYEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
106	TYUMEN	TYEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
107	TYUMEN	TYEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
108	TYUMEN	TYEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
109	TYUMEN	MINATOM	LM	0.00	10000.0	0.00	500.00	1.00	0
110	TYUMEN	MINATOM	LM	0.00	10000.0	0.00	500.00	1.00	0
111	TYUMEN	MINATOM	LM	0.00	10000.0	0.00	500.00	1.00	0
112	FAREAST	FEEnergo	NPP	0.00	1300.0	0.00	10.00	1.00	0
113	FAREAST	MINATOM	NPP	0.00	0.0	0.00	0.00	1.00	0
114	FAREAST	FEEnergo	CHP-A	0.00	0.0	0.00	0.00	1.00	0
115	FAREAST	FEEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
116	FAREAST	FEEnergo	CHP-C	15.19	2600.0	25.19	25.19	1.00	0
117	FAREAST	FEEnergo	CPP-A	0.00	0.0	0.00	0.00	1.00	0
118	FAREAST	FEEnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
119	FAREAST	FEEnergo	GT	0.00	0.0	0.00	0.00	1.00	0
120	FAREAST	FEEnergo	CPP-C	23.02	2700.0	33.02	33.02	1.00	0
121	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
122	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
123	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
124	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
125	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
126	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
127	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
128	FAREAST	LM & Detail	LM	0.00	10000.0	0.00	500.00	1.00	0
129	FAREAST	LM & Detail	LM	0.00	10000.0	0.00	500.00	1.00	0
130	FAREAST	LM & Detail	LM	0.00	10000.0	0.00	500.00	1.00	0
			TOTAL		432,400				

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Scenario: ERI 1995
ERI 1995 Scenario, 07/19/94

(REPMOFF)
RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Inputs Documentation

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21 Jul 94 13:50

1. Enter hours per period, then press enter.
2. Enter expected demand by region, then press "enter" key when finished.

DAY 2

Assign Hours per period:	3	3	3	3	3	3	3	3	0
For all Periods Input Day's Peak Demand (MW) :	Period 1	Period 2	Period 3	Period 4	Period 5	Period 6	Period 7	Period 8	Period 9
NWEST	14400	14400	14400	14400	14400	14400	14400	14400	0
CENTER	51200	51200	51200	51200	51200	51200	51200	51200	0
NCAUC	9600	9600	9600	9600	9600	9600	9600	9600	0
MVOLGA	22400	22400	22400	22400	22400	22400	22400	22400	0
URALS	26800	26800	26800	26800	26800	26800	26800	26800	0
SIBERIA	41200	41200	41200	41200	41200	41200	41200	41200	0
TYUMEN	9700	9700	9700	9700	9700	9700	9700	9700	0
FAREAST	6900	6900	6900	6900	6900	6900	6900	6900	0
Total	182,100	182,100	182,100	182,100	182,100	182,100	182,100	182,100	0

FINANCIAL & OTHER INPUTS

Note: YEARLY INVESTMENT Values should be divided by the SUM of Days in DAY1, DAY2, and DAY3

	Zonal Pool Fixed / Overhead Costs & Investment (Rubles/Day)	Zonal Distribution Fixed / Overhead Costs & Investment (Rubles/Day)	'Regulation' Zonal Wholesale Price (R/MWh)	'Regulation' Zonal Retail Price (R/MWh)	Zonal Grid Tariff (R/MWh)
NWEST	1226908	0	0.00	0.00	0.00
CENTER	4100698	0	0.00	0.00	0.00
NCAUC	2494367	0	0.00	0.00	0.00
MVOLGA	1285942	0	0.00	0.00	0.00
URALS	5695639	0	0.00	0.00	0.00
SIBERIA	4024792	0	0.00	0.00	0.00
TYUMEN	660350	0	0.00	0.00	0.00
FAREAST	3314875	0	0.00	0.00	0.00

LINE CAPACITIES (MW)

Zone	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1600	0	0	0	0	0	0
CENTER	1600	0	1000	4000	0	0	0	0
NCAUC	0	1000	0	0	0	0	0	0
MVOLGA	0	4000	0	0	3000	0	0	0
URALS	0	0	0	1800	0	3000	1000	0
SIBERIA	0	0	0	0	3000	0	0	0
TYUMEN	0	0	0	0	1000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

1. Scenario ID and description got from Control Inputs.
2. Enter numdays, loss factor, stochastic variables, Other decision variables, then press "Enter" key when finished.

DAY 2

Scenario	ID	ERI1995	Used in filename. Maximum 7 letters or numbers, minimum 1.
	Desc.	ERI 1995 Scenario, 07/19/94	Describes scenario. Max 31 char.
Num Days		80	Number of days represented by DAY2
Loss Factor		0.05	Give a value between 0 and 1 for the linear line loss factor
Stochastic Inputs			
plants	pi	1.00	Probability plant will produce expected capacity
	sigma.p	0.50	Multiplier if it doesn't
lines	lambda	1.00	Probability line will be available
	line.d	1.00	Multiplier for lower line capacity
demand	delta.d	0.00	Probability demand will be lower than projected
	sigma.d	0.97	Multiplier for lower demand case (must be < = 1)
	delta.u	1.00	1 - (Probability demand will be higher than projected)
	sigma.u	1.03	Multiplier for higher demand case (must be > = 1)
seed		1	Give an integer value for seed; between 1 and 1000
Market Structure		3	* "1" for Type A; "2" for B; "3" for C;
Alpha		1	Give a value between 0 and 1 for Alpha
			Net line capacity gets multiplied by alpha

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Scenario: ERI1995
ERI 1995 Scenario, 07/19/94

(REPMOFF)
RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Inputs Documentation

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21 Jul 94 13:53

DAY 3

(Note: Total Day In the Year May not be 365

Plant No.	Zone Code	Co. Name	Plant Name	Plant Variable Cost (R/MWh)	Bid Capacity (MW)	Settlement Price (R/MWh)	Dispatch Price (R/MWh)	Plant Availability Factor (betw 0 & 1)	Plant Fixed Costs per Day (Rubles/Day)
0	NWEST	NWEnergo	HPP	0.00	2900.0	10.00	10.00	1.00	0
1	NWEST	MINATOM	NPP	0.00	5800.0	10.00	10.00	1.00	0
2	NWEST	NWEnergo	CHP-A	13.53	2500.0	23.53	23.53	1.00	0
3	NWEST	NWEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
4	NWEST	NWEnergo	CHP-C	13.55	1900.0	23.55	23.55	1.00	0
5	NWEST	NWEnergo	CPP-A	21.54	1200.0	31.54	31.54	1.00	0
6	NWEST	NWEnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
7	NWEST	NWEnergo	GT	0.00	0.0	0.00	0.00	1.00	0
8	NWEST	NWEnergo	CPP-C	0.00	200.0	10.00	10.00	1.00	0
9	NWEST	NWEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
10	NWEST	NWEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
11	NWEST	NWEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
12	NWEST	NWEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
13	NWEST	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
14	NWEST	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
15	NWEST	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
16	CENTER	CNEnergo	HPP	0.00	4900.0	10.00	10.00	1.00	0
17	CENTER	MINATOM	NPP	0.00	12800.0	10.00	10.00	1.00	0
18	CENTER	CNEnergo	CHP-A	15.51	14600.0	25.51	25.51	1.00	0
19	CENTER	CNEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
20	CENTER	CNEnergo	CHP-C	12.65	8200.0	22.65	22.65	1.00	0
21	CENTER	CNEnergo	CPP-A	20.23	7000.0	30.23	30.23	1.00	0
22	CENTER	CNEnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
23	CENTER	CNEnergo	GT	11.78	500.0	21.78	21.78	1.00	0
24	CENTER	CNEnergo	CPP-C	16.83	3300.0	26.83	26.83	1.00	0
25	CENTER	CNEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
26	CENTER	CNEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
27	CENTER	CNEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
28	CENTER	CNEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
29	CENTER	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
30	CENTER	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
31	CENTER	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
32	NCAUC	NCEnergo	HPP	0.00	3000.0	10.00	10.00	1.00	0
33	NCAUC	MINATOM	NPP	0.00	0.0	0.00	0.00	1.00	0
34	NCAUC	NCEnergo	CHP-A	18.99	1900.0	28.99	28.99	1.00	0
35	NCAUC	NCEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
36	NCAUC	NCEnergo	CHP-C	23.54	100.0	33.54	33.54	1.00	0
37	NCAUC	NCEnergo	CPP-A	22.00	3900.0	32.00	32.00	1.00	0
38	NCAUC	NCEnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
39	NCAUC	NCEnergo	GT	0.00	0.0	0.00	0.00	1.00	0
40	NCAUC	NCEnergo	CPP-C	20.61	600.0	30.61	30.61	1.00	0
41	NCAUC	NCEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
42	NCAUC	NCEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
43	NCAUC	NCEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
44	NCAUC	NCEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
45	NCAUC	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
46	NCAUC	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
47	NCAUC	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
48	MVOLGA	MVEnergo	HPP	0.00	6200.0	10.00	10.00	1.00	0
49	MVOLGA	MINATOM	NPP	0.00	4000.0	10.00	10.00	1.00	0
50	MVOLGA	MVEnergo	CHP-A	15.30	9500.0	25.30	25.30	1.00	0
51	MVOLGA	MVEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
52	MVOLGA	MVEnergo	CHP-C	10.60	1400.0	20.60	20.60	1.00	0
53	MVOLGA	MVEnergo	CPP-A	20.42	1300.0	30.42	30.42	1.00	0
54	MVOLGA	MVEnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
55	MVOLGA	MVEnergo	GT	0.00	0.0	0.00	0.00	1.00	0
56	MVOLGA	MVEnergo	CPP-C	0.00	0.0	0.00	0.00	1.00	0
57	MVOLGA	MVEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
58	MVOLGA	MVEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
59	MVOLGA	MVEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
60	MVOLGA	MVEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
61	MVOLGA	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
62	MVOLGA	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
63	MVOLGA	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
64	URALS	UREnergo	HPP	0.00	1800.0	10.00	10.00	1.00	0
65	URALS	MINATOM	NPP	0.00	600.0	10.00	10.00	1.00	0

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Scenario: ER1995
ER 1995 Scenario, 07/19/94

(REPMOFF)
RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Inputs Documentation

21 Jul 94 13:59

DAY 3

(Note: Total Days in the Year May not be 365 !)

Plant No.	Zone Code	Co. Name	Plant Name	Plant Variable Cost (R/MWh)	Bid Capacity (MW)	Settlement Price (R/MWh)	Dispatch Price (R/MWh)	Plant Availability Factor (betw 0 & 1)	Plant Fixed Costs per Day (Rubles/Day)
66	URALS	UREnergo	CHP-A	13.74	5200.0	23.74	23.74	1.00	0
67	URALS	UREnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
68	URALS	UREnergo	CHP-C	9.64	6600.0	19.64	19.64	1.00	0
69	URALS	UREnergo	CPP-A	17.64	7500.0	27.64	27.64	1.00	0
70	URALS	UREnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
71	URALS	UREnergo	GT	0.00	0.0	0.00	0.00	1.00	0
72	URALS	UREnergo	CPP-C	11.43	5200.0	21.43	21.43	1.00	0
73	URALS	UREnergo	Other	0.00	0.0	0.00	0.00	1.00	0
74	URALS	UREnergo	Other	0.00	0.0	0.00	0.00	1.00	0
75	URALS	UREnergo	Other	0.00	0.0	0.00	0.00	1.00	0
76	URALS	UREnergo	Other	0.00	0.0	0.00	0.00	1.00	0
77	URALS	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
78	URALS	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
79	URALS	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
80	SIBERIA	SIEnergo	HPP	0.00	22300.0	10.00	10.00	1.00	0
81	SIBERIA	MINATOM	NPP	0.00	0.0	0.00	0.00	1.00	0
82	SIBERIA	SIEnergo	CHP-A	0.00	0.0	0.00	0.00	1.00	0
83	SIBERIA	SIEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
84	SIBERIA	SIEnergo	CHP-C	5.03	14300.0	15.03	15.03	1.00	0
85	SIBERIA	SIEnergo	CPP-A	0.00	0.0	0.00	10.00	1.00	0
86	SIBERIA	SIEnergo	CPP-B	0.00	0.0	0.00	10.00	1.00	0
87	SIBERIA	SIEnergo	GT	0.00	0.0	0.00	10.00	1.00	0
88	SIBERIA	SIEnergo	CPP-C	6.60	4600.0	16.60	16.60	1.00	0
89	SIBERIA	SIEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
90	SIBERIA	SIEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
91	SIBERIA	SIEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
92	SIBERIA	SIEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
93	SIBERIA	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
94	SIBERIA	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
95	SIBERIA	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
96	TYUMEN	TYEnergo	HPP	0.00	0.0	0.00	0.00	1.00	0
97	TYUMEN	MINATOM	NPP	0.00	0.0	0.00	0.00	1.00	0
98	TYUMEN	TYEnergo	CHP-A	12.69	1700.0	22.69	22.69	1.00	0
99	TYUMEN	TYEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
100	TYUMEN	TYEnergo	CHP-C	5.08	8000.0	15.08	15.08	1.00	0
101	TYUMEN	TYEnergo	CPP-A	0.00	0.0	0.00	0.00	1.00	0
102	TYUMEN	TYEnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
103	TYUMEN	TYEnergo	GT	0.00	0.0	0.00	0.00	1.00	0
104	TYUMEN	TYEnergo	CPP-C	0.00	0.0	0.00	0.00	1.00	0
105	TYUMEN	TYEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
106	TYUMEN	TYEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
107	TYUMEN	TYEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
108	TYUMEN	TYEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
109	TYUMEN	MINATOM	LM	0.00	10000.0	0.00	500.00	1.00	0
110	TYUMEN	MINATOM	LM	0.00	10000.0	0.00	500.00	1.00	0
111	TYUMEN	MINATOM	LM	0.00	10000.0	0.00	500.00	1.00	0
112	FAREAST	FEEnergo	HPP	0.00	1300.0	0.00	10.00	1.00	0
113	FAREAST	MINATOM	NPP	0.00	0.0	0.00	0.00	1.00	0
114	FAREAST	FEEnergo	CHP-A	0.00	0.0	0.00	0.00	1.00	0
115	FAREAST	FEEnergo	CHP-B	0.00	0.0	0.00	0.00	1.00	0
116	FAREAST	FEEnergo	CHP-C	15.19	2900.0	25.19	25.19	1.00	0
117	FAREAST	FEEnergo	CPP-A	0.00	0.0	0.00	0.00	1.00	0
118	FAREAST	FEEnergo	CPP-B	0.00	0.0	0.00	0.00	1.00	0
119	FAREAST	FEEnergo	GT	0.00	0.0	0.00	0.00	1.00	0
120	FAREAST	FEEnergo	CPP-C	23.02	2700.0	33.02	33.02	1.00	0
121	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
122	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
123	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
124	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
125	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
126	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
127	FAREAST	FEEnergo	Other	0.00	0.0	0.00	0.00	1.00	0
128	FAREAST	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
129	FAREAST	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
130	FAREAST	LM & Deficit	LM	0.00	10000.0	0.00	500.00	1.00	0
			TOTAL		422,400				

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Scenario: ERI1995
ERI 1995 Scenario, 07/19/94

(REPMOFF)
RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Inputs Documentation

CYRPORPON PWC
21 JUL 94 1353

1. Enter hours per period, then press enter.
2. Enter expected demand by region, then press "enter" key when finished.

DAY 3

Assign Hours per period:	3	3	3	3	3	3	3	3	0
For all Periods Input Day's Peak Demand (MW):	Period 1	Period 2	Period 3	Period 4	Period 5	Period 6	Period 7	Period 8	Period 9
NWEST	14400	14400	14400	14400	14400	14400	14400	14400	0
CENTER	51200	51200	51200	51200	51200	51200	51200	51200	0
NCAUC	9500	9500	9500	9500	9500	9500	9500	9500	0
MVOLGA	22400	22400	22400	22400	22400	22400	22400	22400	0
URALS	26800	26800	26800	26800	26800	26800	26800	26800	0
SIBERIA	41200	41200	41200	41200	41200	41200	41200	41200	0
TYUMEN	9700	9700	9700	9700	9700	9700	9700	9700	0
FAREAST	6900	6900	6900	6900	6900	6900	6900	6900	0
Total	182,100	182,100	182,100	182,100	182,100	182,100	182,100	182,100	0

FINANCIAL & OTHER INPUTS

Note: YEARLY INVESTMENT Values should be divided by the SUM of Days in DAY1, DAY2, and DAY3

	Zonal Pool Fixed / Overhead Costs & Investment (Rubles/Day)	Zonal Distributb Fixed / Overhead Costs & Investment (Rubles/Day)	'Regulation' Zonal Wholesale Price (R/MWh)	'Regulation' Zonal Retail Price (R/MWh)	Zonal Grid Tariff (R/MWh)
NWEST	1,226,908	0	0.00	0.00	0.00
CENTER	4,100,696	0	0.00	0.00	0.00
NCAUC	2,404,367	0	0.00	0.00	0.00
MVOLGA	1,265,942	0	0.00	0.00	0.00
URALS	5,965,636	0	0.00	0.00	0.00
SIBERIA	4,024,792	0	0.00	0.00	0.00
TYUMEN	680,350	0	0.00	0.00	0.00
FAREAST	3,314,875	0	0.00	0.00	0.00

LINE CAPACITIES (MW)

Zone	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1600	0	0	0	0	0	0
CENTER	1600	0	1000	4000	0	0	0	0
NCAUC	0	1000	0	0	0	0	0	0
MVOLGA	0	4000	0	0	3000	0	0	0
URALS	0	0	0	1800	0	3000	1000	0
SIBERIA	0	0	0	0	3000	0	0	0
TYUMEN	0	0	0	0	1000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

1. Scenario ID and description got from Control Inputs. DAY 3
2. Enter numdays, loss factor, stochastic variables, Other decision variables, then press "Enter" key when finished.

Scenario	ID	ERI1995	Used in filename. Maximum 7 letters or numbers, minimum 1.
	Desc.	ERI 1995 Scenario, 07/19/94	Describes scenario. Max 31 char.
Num Days		80	Number of days represented by DAY3
Loss Factor		0.05	Give a value between 0 and 1 for the linear line loss factor
Stochastic Inputs			
plants	pi	1.00	Probability plant will produce expected capacity
	sigma.p	0.50	Multiplier if it doesn't
lines	lambda	1.00	Probability line will be available
	line.d	1.00	Multiplier for lower line capacity
demand	delta.d	0.00	Probability demand will be lower than projected
	sigma.d	0.97	Multiplier for lower demand case (must be <= 1)
	delta.u	1.00	1 – (Probability demand will be higher than projected)
	sigma.u	1.03	Multiplier for higher demand case (must be >= 1)
seed		1	Give an integer value for seed; between 1 and 1000
Market Structure		3	"1" for Type A; "2" for B; "3" for C;
Alpha		1	Give a value between 0 and 1 for Alpha Net line capacity gets multiplied by alpha

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APPENDIX E

Financial Outputs

The following are the financial outputs produced by the model for the data input sheets presented earlier and for Type A market structure. Financial results for Types B and C market structures can be easily produced by running the model under those scenarios.

Scenario:	ERI1995
AGGREGATE FOR THE YEAR	
ERI 1995 Scenario, 07/19/94	

RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Cash Flow Summary by Company
(In Rubles)

Optimization Results
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(Rubles)

Company				Income		
Russian Grid	0	0	0	0		
						Income
NWEnergo	749,068,864	0	(329,138,016)	0	0	419,930,848
CNEnergo	4,346,162,688	0	(2,451,849,024)	0	0	1,894,513,920
NCEnergo	939,150,720	0	(515,070,720)	0	0	424,080,000
MVEnergo	1,895,329,920	0	(917,135,424)	0	0	978,194,496
UREnergo	2,945,729,024	0	(1,594,222,848)	0	0	1,351,506,176
SIEnergo	2,910,910,976	0	(568,751,104)	0	0	2,342,159,872
TYEnergo	907,819,776	0	(352,159,776)	0	0	555,660,032
FEEnergo	821,110,912	0	(532,830,144)	0	0	288,280,800
MINATOM	1,336,320,000	0	0	0	0	1,336,320,000
LM & Deficit	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0

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						Income
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Total	16,851,602,880	0	(7,260,957,056)	0	0	9,590,646,144

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Scenario: ERI1995
AGGREGATE FOR THE YEAR
ERI 1995 Scenario, 07/19/94

RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Cash Flow Summary by Company
(in Rubles)

Optimization Results
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1. Zonal Pool Yearly Income Statements and Wholesale Prices.

(Rubles)

Zonal Pool						Income	Actual Wholesale Price (R/MWh)	Benchmark Wholesale Price (R/MWh)
NWEST	0	101,736,000	(1,083,148,800)	(26,895,420)	(294,457,920)	(1,302,766,080)	0.00	18.03
CENTER	0	64,380,264	(5,083,443,200)	(92,627,728)	(984,167,040)	(6,095,857,664)	0.00	23.00
NCAUC	0	0	(939,150,720)	(133,565,456)	(598,648,064)	(1,671,364,224)	0.00	34.91
MVOLGA	0	88,900,336	(2,125,729,920)	(46,977,628)	(303,826,080)	(2,387,633,152)	0.00	20.08
URALS	0	25,888,960	(2,960,269,024)	(195,876,128)	(1,436,553,088)	(4,586,829,312)	0.00	31.36
SIBERIA	0	155,423,808	(2,910,910,976)	0	(965,950,080)	(3,721,437,440)	0.00	16.55
TYUMEN	0	59,612,988	(907,819,776)	0	(163,284,000)	(1,011,490,752)	0.00	19.11
FAREAST	0	0	(821,110,912)	0	(795,569,984)	(1,616,680,960)	0.00	44.52

Yearly Average Benchmark	System Wholesale Price	(R/MWh)	23.22

2. Zonal Distribution Company Yearly Income Statements.

(Rubles)

Zonal Distribution Company	Market	Wholesale Market	Grid Tariff Costs	Fixed & Over-head Costs & Investments	Income	Grid Tariff (R/MWh)	Actual Retail Price (R/MWh)	Benchmark Retail Price 1 (R/MWh)	Benchmark Retail Price 2 (R/MWh)
NWEST	0	0	0	0	0	0.00	0.00	18.03	0.00
CENTER	0	0	0	0	0	0.00	0.00	23.00	0.00
NCAUC	0	0	0	0	0	0.00	0.00	34.91	0.00
MVOLGA	0	0	0	0	0	0.00	0.00	20.08	0.00
URALS	0	0	0	0	0	0.00	0.00	31.36	0.00
SIBERIA	0	0	0	0	0	0.00	0.00	16.55	0.00
TYUMEN	0	0	0	0	0	0.00	0.00	19.11	0.00
FAREAST	0	0	0	0	0	0.00	0.00	44.52	0.00

Yearly Average Benchmark	System Retail Price 1	(R/MWh)	23.22
Yearly Average Benchmark	System Retail Price 2	(R/MWh)	0.00

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Scenario:	ERI 1995
	DAY 1
ERI 1995 Scenario, 07/19/94	

(REPMOFF)
RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Cash Flow Summary by Company (Rubles)

Optimization Results
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(Rubles)

Company	Tariff Earnings	Line Maint Costs	Fixed & Over-head Costs	Income	
Russian Grid	0	0	0	0	

	Energy Earnings	Total Uplift Earnings	Variable Costs	Fixed Costs	Overhead Costs	Income
NWEnergo	3,121,120	0	(1,371,408)	0	0	1,749,712
CNEnergo	18,109,012	0	(10,215,204)	0	0	7,893,808
NCEnergo	3,913,128	0	(2,146,128)	0	0	1,767,000
MVEnergo	7,897,206	0	(3,821,396)	0	0	4,075,810
UREnergo	12,273,871	0	(6,642,595)	0	0	5,631,276
SIEnergo	12,128,796	0	(2,369,796)	0	0	9,759,000
TYEnergo	3,782,582	0	(1,467,332)	0	0	2,315,250
FEEnergo	3,421,296	0	(2,220,126)	0	0	1,201,170
MINATOM	5,566,000	0	0	0	0	5,566,000
LM & Deficit	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
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Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
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Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
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Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0

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	Energy Earnings	Total Uplift Earnings	Variable Costs	Fixed Costs	Overhead Costs	Income
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Total	**70,215,013**	**0**	**(30,253,987)**	**0**	**0**	**39,961,026**

Scenario:	ERI 1995
	DAY 1
ERI 1995 Scenario, 07/18/94	

(REPMOFF)
RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Cash Flow Summary by Zone (Rubles)

Optimization Results
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21 Jul 94 14:43

1. Zonal Pool Income Statements and Wholesale Prices.

(RUBLES)

Zonal Pool	Sales Revenue from Wholesale Market	Export Earnings	Costs of Buying Power from Generators	Import Costs	Fixed and Overhead Costs	Income	Actual Wholesale Price (R/MWh)	Benchmark Wholesale Price (R/MWh)
NWEST	0	423,900	(4,513,120)	(112,064)	(1,226,908)	(5,428,192)	0.00	18.03
CENTER	0	268,251	(21,181,014)	(386,946)	(4,100,696)	(25,399,408)	0.00	23.00
NCAUC	0	0	(3,913,128)	(556,523)	(2,494,367)	(6,964,018)	0.00	34.91
MVOLGA	0	370,418	(8,857,208)	(195,740)	(1,266,942)	(9,948,472)	0.00	20.06
URALS	0	107,871	(12,417,671)	(816,150)	(5,985,638)	(19,111,788)	0.00	31.36
SIBERIA	0	647,568	(12,128,798)	0	(4,024,792)	(15,506,986)	0.00	16.55
TYUMEN	0	248,367	(3,792,562)	0	(680,350)	(4,214,545)	0.00	19.11
FAREAST	0	0	(3,421,288)	0	(3,314,875)	(6,736,170)	0.00	44.52

Daily average benchmark system wholesale price	(R/MWh)	23.22

2. Zonal Distribution Company Income Statements.

(RUBLES)

Zonal Distribution Company	Sales Revenue from Retail Market	Costs of Buying Power from Wholesale Market	Grid Tariff Costs	Fixed and Overhead Costs	Income	Grid Tariff (R/MWh)	Actual Retail Price (R/MWh)	Benchmark Retail Price 1 (R/MWh)	Benchmark Retail Price 2 (R/MWh)
NWEST	0	0	0	0	0	0.00	0.00	18.03	0.00
CENTER	0	0	0	0	0	0.00	0.00	23.00	0.00
NCAUC	0	0	0	0	0	0.00	0.00	34.91	0.00
MVOLGA	0	0	0	0	0	0.00	0.00	20.06	0.00
URALS	0	0	0	0	0	0.00	0.00	31.36	0.00
SIBERIA	0	0	0	0	0	0.00	0.00	16.55	0.00
TYUMEN	0	0	0	0	0	0.00	0.00	19.11	0.00
FAREAST	0	0	0	0	0	0.00	0.00	44.52	0.00

Daily average benchmark system retail price 1	(R/MWh)	23.22
Daily average benchmark system retail price 2	(R/MWh)	0.00

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Scenario:	ERI 1995
	DAY 2
ERI 1995 Scenario, 07/19/94	

(REPMOFF)
RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Cash Flow Summary by Company (Rubles)

Optimization Results
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(Rubles)

Company	Tariff Earnings	Line Maint Costs	Fixed & Over-head Costs	Income	
Russian Grid	0	0	0	0	
	Energy Earnings	Total Uplift Earnings	Variable Costs	Fixed Costs	Overhead Costs	Income
NWEnergo	3,121,120	0	(1,371,408)	0	0	1,749,712
CNEnergo	18,109,012	0	(10,215,204)	0	0	7,893,808
NCEnergo	3,913,128	0	(2,146,128)	0	0	1,767,000
MVEnergo	7,897,208	0	(3,821,398)	0	0	4,075,810
UREnergo	12,273,871	0	(6,642,596)	0	0	5,631,276
SIEnergo	12,128,796	0	(2,369,796)	0	0	9,759,000
TYEnergo	3,782,582	0	(1,467,332)	0	0	2,315,250
FEEnergo	3,421,296	0	(2,220,126)	0	0	1,201,170
MINATOM	5,568,000	0	0	0	0	5,568,000
LM & Deficit	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0

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	Energy Earnings	Total Uplift Earnings	Variable Costs	Fixed Costs	Overhead Costs	Income
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Total	70,215,013	0	(30,253,987)	0	0	39,961,026

Scenario:	ERI 1995
	DAY 2
ERI 1995 Scenario, 07/16/94	

(REPMOFF)
RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Cash Flow Summary by Zone (Rubles)

Optimization Results
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1. Zonal Pool Income Statements and Wholesale Prices.

(RUBLES)

Zonal Pool	Sales Revenue from Wholesale Market	Export Earnings	Costs of Buying Power from Generators	Import Costs	Fixed and Overhead Costs	Income	Actual Wholesale Price (R/MWh)	Benchmark Wholesale Price (R/MWh)
NWEST	0	423,900	(4,513,120)	(112,064)	(1,226,908)	(5,428,192)	0.00	18.03
CENTER	0	269,251	(21,181,014)	(386,946)	(4,100,695)	(25,399,408)	0.00	23.00
NCAUC	0	0	(3,913,128)	(556,523)	(2,494,367)	(6,964,018)	0.00	34.91
MVOLGA	0	370,418	(8,867,209)	(195,740)	(1,265,942)	(9,948,472)	0.00	20.06
URALS	0	107,871	(12,417,871)	(816,150)	(5,985,638)	(19,111,788)	0.00	31.36
SIBERIA	0	647,569	(12,128,796)	0	(4,024,792)	(15,505,999)	0.00	16.56
TYUMEN	0	249,387	(3,782,582)	0	(680,350)	(4,214,545)	0.00	19.11
FAREAST	0	0	(3,421,268)	0	(3,314,875)	(6,736,170)	0.00	44.52

Daily average benchmark system wholesale price	(R/MWh)	23.22

2. Zonal Distribution Company Income Statements.

(RUBLES)

Zonal Distribution Company	Sales Revenue from Retail Market	Costs of Buying Power from Wholesale Market	Grid Tariff Costs	Fixed and Overhead Costs	Income	Grid Tariff (R/MWh)	Actual Retail Price (R/MWh)	Benchmark Retail Price 1 (R/MWh)	Benchmark Retail Price 2 (R/MWh)
NWEST	0	0	0	0	0	0.00	0.00	18.03	0.00
CENTER	0	0	0	0	0	0.00	0.00	23.00	0.00
NCAUC	0	0	0	0	0	0.00	0.00	34.91	0.00
MVOLGA	0	0	0	0	0	0.00	0.00	20.06	0.00
URALS	0	0	0	0	0	0.00	0.00	31.36	0.00
SIBERIA	0	0	0	0	0	0.00	0.00	16.56	0.00
TYUMEN	0	0	0	0	0	0.00	0.00	19.11	0.00
FAREAST	0	0	0	0	0	0.00	0.00	44.52	0.00

Daily average benchmark system retail price 1	(R/MWh)	23.22
Daily average benchmark system retail price 2	(R/MWh)	0.00

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Scenario:	ERI 1995
	DAY 3
ERI 1995 Scenario, 07/19/94	

(REPMOFF)
RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Cash Flow Summary by Company (Rubles)

Optimization Results
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(Rubles)

Company	Tariff Earnings	Line Maint Costs	Fixed & Over-head Costs	Income		
Russian Grid	0	0	0	0		
	Energy Earnings	Total Uplift Earnings	Variable Costs	Fixed Costs	Overhead Costs	Income
NWEnergo	3,121,120	0	(1,371,408)	0	0	1,749,712
CNEnergo	18,109,012	0	(10,215,204)	0	0	7,893,808
NCEnergo	3,913,128	0	(2,146,128)	0	0	1,767,000
MVEnergo	7,897,208	0	(3,821,398)	0	0	4,075,810
UREnergo	12,273,871	0	(6,642,595)	0	0	5,631,276
SIEnergo	12,128,796	0	(2,369,796)	0	0	9,759,000
TYEnergo	3,782,582	0	(1,467,332)	0	0	2,315,250
FEEnergo	3,421,296	0	(2,220,126)	0	0	1,201,170
MINATOM	5,568,000	0	0	0	0	5,568,000
LM & Deficit	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0

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	Energy Earnings	Total Uplift Earnings	Variable Costs	Fixed Costs	Overhead Costs	Income
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Company X	0	0	0	0	0	0
Total	**70,215,013**	**0**	**(30,253,987)**	**0**	**0**	**39,961,026**

Scenario:	ERI 1995
	DAY 3
ERI 1995 Scenario, 07/19/94	

(REPMOFF)

RUSSIAN ELECTRIC POWER MARKET

OPERATIONAL & FINANCIAL FRAMEWORK

Cash Flow Summary by Zone (Rubles)

Optimization Results

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1. Zonal Pool Income Statements and Wholesale Prices.

(RUBLES)

Zonal Pool	Sales Revenue from Wholesale Market	Export Earnings	Costs of Buying Power from Generators	Import Costs	Fixed and Overhead Costs	Income	Actual Wholesale Price (R/MWh)	Benchmark Wholesale Price (R/MWh)
NWEST	0	429,900	(4,513,129)	(112,064)	(1,228,908)	(5,428,192)	0.00	18.03
CENTER	0	268,251	(21,181,014)	(365,948)	(4,100,668)	(25,379,408)	0.00	23.00
NCAUC	0	0	(5,913,129)	(556,523)	(2,494,367)	(8,964,018)	0.00	34.91
MVOLGA	0	370,416	(8,857,208)	(196,740)	(1,265,942)	(9,948,472)	0.00	20.06
URALS	0	107,871	(12,417,871)	(816,150)	(5,985,639)	(19,111,789)	0.00	31.36
SIBERA	0	647,569	(12,129,798)	0	(4,024,792)	(15,506,989)	0.00	16.55
TYUMEN	0	248,367	(5,782,562)	0	(680,350)	(4,214,545)	0.00	19.11
FAREAST	0	0	(5,421,298)	0	(3,314,875)	(8,736,170)	0.00	44.52

Daily average benchmark system wholesale price	(R/MWh)	23.22

2. Zonal Distribution Company Income Statements.

(RUBLES)

Zonal Distribution Company	Sales Revenue from Retail Market	Costs of Buying Power from Wholesale Market	Grid Tariff Costs	Fixed and Overhead Costs	Income	Grid Tariff (R/MWh)	Actual Retail Price (R/MWh)	Benchmark Retail Price 1 (R/MWh)	Benchmark Retail Price 2 (R/MWh)
NWEST	0	0	0	0	0	0.00	0.00	18.03	0.00
CENTER	0	0	0	0	0	0.00	0.00	23.00	0.00
NCAUC	0	0	0	0	0	0.00	0.00	34.91	0.00
MVOLGA	0	0	0	0	0	0.00	0.00	20.06	0.00
URALS	0	0	0	0	0	0.00	0.00	31.36	0.00
SIBERA	0	0	0	0	0	0.00	0.00	16.55	0.00
TYUMEN	0	0	0	0	0	0.00	0.00	19.11	0.00
FAREAST	0	0	0	0	0	0.00	0.00	44.52	0.00

Daily average benchmark system retail price 1	(R/MWh)	23.22
Daily average benchmark system retail price 2	(R/MWh)	0.00

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APPENDIX F

Physical Outputs

The following are the physical outputs produced by the model for the data input sheets presented earlier and for Type A market structure. Physical results for Types B and C market structures can be easily produced by running the model under those scenarios.

AGGREGATE OUTPUTS

Scenario:	ERI1995 AGGREGATE
ERI 1995 Scenario, 07/19/94	

(REPMOFF)
Russian Electric Power Market
Operational & Financial Framework
Aggregate Physical Outputs

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1. Aggregate Consumption, Generation, Shortage, Capacity, Import and Export (By Zones)

Zone	Consumption (mill MWh)	Generation (mill MWh)	Shortage (mill MWh)	Peak Shortag (MW)	Available Adjusted Capacity (in MW) Day1	Day2	Day3	Average for all Day Types	Total Exports (mill MWh)	Total Imports (mill MWh)
NWEST	72.27	75.40	0.00	0.00	14,500	14,500	14,500	14,500	4.32	1.18
CENTER	265.05	263.18	0.00	0.00	51,300	51,300	51,300	51,300	2.16	4.03
NCAUC	47.88	42.41	0.00	0.00	9,500	9,500	9,500	9,500	0.00	5.47
MVOLGA	119.03	120.86	0.00	0.00	22,400	22,400	22,400	22,400	3.51	1.68
URALS	146.26	138.61	0.00	0.00	26,900	26,900	26,900	26,900	0.94	8.59
SIBERIA	224.85	234.22	0.00	0.00	41,200	41,200	41,200	41,200	9.36	0.00
TYUMEN	52.94	55.57	0.00	0.00	9,700	9,700	9,700	9,700	2.63	0.00
FAREAST	36.32	36.32	0.00	0.00	6,900	6,900	6,900	6,900	0.00	0.00
Total	**964.59**	**966.55**	**0.00**	**0.00**	**182400.00**	**182400.00**	**182400.00**	**182400.00**	**22.92**	**20.96**

2. Aggregate Line Activity (In Hours)

								FAREAST
NWEST	NA	1,440	NA	NA	NA	NA	NA	NA
CENTER	0	NA	5,760	0	NA	NA	NA	NA
NCAUC	NA	0	NA	NA	NA	NA	NA	NA
MVOLGA	NA	0	NA	NA	720	NA	NA	NA
URALS	NA	NA	NA	2,880	NA	0	0	NA
SIBERIA	NA	NA	NA	NA	1,440	NA	NA	NA
TYUMEN	NA	NA	NA	NA	1,440	NA	NA	NA
FAREAST	NA	NA	NA	NA	NA	NA	NA	NA

3. Line Utilization (in Percentage)

Total Number of Hours in an Aggregate REPMOFF Run 5,760

								FAREAST
NWEST	NA	25.0%	NA	NA	NA	NA	NA	NA
CENTER	0.0%	NA	100.0%	0.0%	NA	NA	NA	NA
NCAUC	NA	0.0%	NA	NA	NA	NA	NA	NA
MVOLGA	NA	0.0%	NA	NA	12.5%	NA	NA	NA
URALS	NA	NA	NA	50.0%	NA	0.0%	0.0%	NA
SIBERIA	NA	NA	NA	NA	25.0%	NA	NA	NA
TYUMEN	NA	NA	NA	NA	25.0%	NA	NA	NA
FAREAST	NA	NA	NA	NA	NA	NA	NA	NA

4. Line Shadow Price (In Rubles)

								FAREAST
NWEST	NA	136,668,352	NA	NA	NA	NA	NA	NA
CENTER	NA	NA	199,690,080	NA	NA	NA	NA	NA
NCAUC	NA	NA	NA	NA	NA	NA	NA	NA
MVOLGA	NA	NA	NA	NA	(41,160)	NA	NA	NA
URALS	NA	NA	NA	663,120	NA	NA	NA	NA
SIBERIA	NA	NA	NA	NA	(169,426,720)	NA	NA	NA
TYUMEN	NA	NA	NA	NA	(376,262,668)	NA	NA	NA
FAREAST	NA	NA	NA	NA	NA	NA	NA	NA

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AGGREGATE OUTPUTS

Scenario:	ERI1995
	AGGREGATE
ERI 1995 Scenario, 07/19/94	

(REPMOFF)
Russian Electric Power Market
Operational & Financial Framework
Aggregate Physical Outputs

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5. Plant Usage (In Hrs) and Utilization (In Percentage)

Plant No.	Zone	Company	Plant	C-On Plant Usage (In Hours)	Total Plant Usage (In Hours)	Total Plant Utilization (In Percent)	Shadow Price (Rubles)
0	NWEST	NWEnergo	HPP	0	5,760	100.0%	102,960
1	NWEST	MINATOM	NPP	0	5,760	100.0%	110,040
2	NWEST	NWEnergo	CHP-A	0	5,760	100.0%	(64,800)
3	NWEST	NWEnergo	CHP-B	0	0	0.0%	NA
4	NWEST	NWEnergo	CHP-C	0	4,969	86.3%	(109,200)
5	NWEST	NWEnergo	CPP-A	0	247	4.3%	(6,273,240)
6	NWEST	NWEnergo	CPP-B	0	0	0.0%	NA
7	NWEST	NWEnergo	GT	0	0	0.0%	NA
8	NWEST	NWEnergo	CPP-C	0	5,760	100.0%	(32,949,840)
9	NWEST	NWEnergo	Other	0	0	0.0%	NA
10	NWEST	NWEnergo	Other	0	0	0.0%	NA
11	NWEST	NWEnergo	Other	0	0	0.0%	NA
12	NWEST	NWEnergo	Other	0	0	0.0%	NA
13	NWEST	LM & Deficit	LM	0	0	0.0%	NA
14	NWEST	LM & Deficit	LM	0	0	0.0%	NA
15	NWEST	LM & Deficit	LM	0	0	0.0%	NA
16	CENTER	CNEnergo	HPP	0	5760	100.0%	(3,731,040)
17	CENTER	MINATOM	NPP	0	5760	100.0%	(3,744,120)
18	CENTER	CNEnergo	CHP-A	0	5531.2	96.0%	(12,360,000)
19	CENTER	CNEnergo	CHP-B	0	0	0.0%	NA
20	CENTER	CNEnergo	CHP-C	0	5760	100.0%	(8,746,920)
21	CENTER	CNEnergo	CPP-A	0	2385	41.4%	(137,765,152)
22	CENTER	CNEnergo	CPP-B	0	0	0.0%	NA
23	CENTER	CNEnergo	GT	0	5759.9	100.0%	(49,938,240)
24	CENTER	CNEnergo	CPP-C	0	4141	71.9%	(168,058,840)
25	CENTER	CNEnergo	Other	0	0	0.0%	NA
26	CENTER	CNEnergo	Other	0	0	0.0%	NA
27	CENTER	CNEnergo	Other	0	0	0.0%	NA
28	CENTER	CNEnergo	Other	0	0	0.0%	NA
29	CENTER	LM & Deficit	LM	0	0	0.0%	NA
30	CENTER	LM & Deficit	LM	0	0	0.0%	NA
31	CENTER	LM & Deficit	LM	0	0	0.0%	NA
32	NCAUC	NCEnergo	HPP	0	5760	100.0%	128,720
33	NCAUC	MINATOM	NPP	0	0	0.0%	NA
34	NCAUC	NCEnergo	CHP-A	0	5760	100.0%	17,280
35	NCAUC	NCEnergo	CHP-B	0	0	0.0%	NA
36	NCAUC	NCEnergo	CHP-C	0	0	0.0%	NA
37	NCAUC	NCEnergo	CPP-A	0	2750.8	47.8%	(180,352,080)
38	NCAUC	NCEnergo	CPP-B	0	0	0.0%	NA
39	NCAUC	NCEnergo	GT	0	0	0.0%	NA
40	NCAUC	NCEnergo	CPP-C	0	5760	100.0%	8,640
41	NCAUC	NCEnergo	Other	0	0	0.0%	NA
42	NCAUC	NCEnergo	Other	0	0	0.0%	NA
43	NCAUC	NCEnergo	Other	0	0	0.0%	NA
44	NCAUC	NCEnergo	Other	0	0	0.0%	NA
45	NCAUC	LM & Deficit	LM	0	0	0.0%	NA
46	NCAUC	LM & Deficit	LM	0	0	0.0%	NA
47	NCAUC	LM & Deficit	LM	0	0	0.0%	NA
48	MVOLGA	MVEnergo	HPP	0	5760	100.0%	76,937,040
49	MVOLGA	MINATOM	NPP	0	5760	100.0%	(40,350,960)
50	MVOLGA	MVEnergo	CHP-A	0	5590.3	97.1%	(199,391,999)
51	MVOLGA	MVEnergo	CHP-B	0	0	0.0%	NA
52	MVOLGA	MVEnergo	CHP-C	0	5760	100.0%	33,990,840
53	MVOLGA	MVEnergo	CPP-A	0	720	12.5%	(484,810,592)
54	MVOLGA	MVEnergo	CPP-B	0	0	0.0%	NA
55	MVOLGA	MVEnergo	GT	0	0	0.0%	NA
56	MVOLGA	MVEnergo	CPP-C	0	0	0.0%	NA
57	MVOLGA	MVEnergo	Other	0	0	0.0%	NA
58	MVOLGA	MVEnergo	Other	0	0	0.0%	NA
59	MVOLGA	MVEnergo	Other	0	0	0.0%	NA
60	MVOLGA	MVEnergo	Other	0	0	0.0%	NA
61	MVOLGA	LM & Deficit	LM	0	0	0.0%	NA
62	MVOLGA	LM & Deficit	LM	0	0	0.0%	NA
63	MVOLGA	LM & Deficit	LM	0	0	0.0%	NA
64	URALS	UREnergo	HPP	0	5760	100.0%	144,520,560
65	URALS	MINATOM	NPP	0	5760	100.0%	131,912,400
66	URALS	UREnergo	CHP-A	0	5760	100.0%	131,932,800
67	URALS	UREnergo	CHP-B	0	0	0.0%	NA
68	URALS	UREnergo	CHP-C	0	5760	100.0%	132,001,800
69	URALS	UREnergo	CPP-A	0	3581.7	62.2%	(26,307,600)
70	URALS	UREnergo	CPP-B	0	0	0.0%	NA
71	URALS	UREnergo	GT	0	0	0.0%	NA
72	URALS	UREnergo	CPP-C	0	5760	100.0%	146,198,432
73	URALS	UREnergo	Other	0	0	0.0%	NA
74	URALS	UREnergo	Other	0	0	0.0%	NA
75	URALS	UREnergo	Other	0	0	0.0%	NA
76	URALS	UREnergo	Other	0	0	0.0%	NA
77	URALS	LM & Deficit	LM	0	0	0.0%	NA
78	URALS	LM & Deficit	LM	0	0	0.0%	NA
79	URALS	LM & Deficit	LM	0	0	0.0%	NA
80	SIBERIA	SIEnergo	HPP	0	5760	100.0%	137,116,192
81	SIBERIA	MINATOM	NPP	0	0	0.0%	NA
82	SIBERIA	SIEnergo	CHP-A	0	0	0.0%	NA
83	SIBERIA	SIEnergo	CHP-B	0	0	0.0%	NA
84	SIBERIA	SIEnergo	CHP-C	0	5760	100.0%	137,152,512
85	SIBERIA	SIEnergo	CPP-A	0	0	0.0%	NA
86	SIBERIA	SIEnergo	CPP-B	0	0	0.0%	NA
87	SIBERIA	SIEnergo	GT	0	0	0.0%	NA
88	SIBERIA	SIEnergo	CPP-C	0	5087	88.3%	137,153,520
89	SIBERIA	SIEnergo	Other	0	0	0.0%	NA
90	SIBERIA	SIEnergo	Other	0	0	0.0%	NA

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91	SIBERIA	SIEnergo	Other	0	0	0.0%	NA
92	SIBERIA	SIEnergo	Other	0	0	0.0%	NA
93	SIBERIA	LM & Deficit	LM	0	0	0.0%	NA
94	SIBERIA	LM & Deficit	LM	0	0	0.0%	NA
95	SIBERIA	LM & Deficit	LM	0	0	0.0%	NA
96	TYUMEN	TYEnergo	HPP	0	0	0.0%	NA
97	TYUMEN	MINATOM	NPP	0	0	0.0%	NA
98	TYUMEN	TYEnergo	CHP-A	0	5580	96.9%	137,153,520
99	TYUMEN	TYEnergo	CHP-B	0	0	0.0%	NA
100	TYUMEN	TYEnergo	CHP-C	0	5760	100.0%	137,211,840
101	TYUMEN	TYEnergo	CPP-A	0	0	0.0%	NA
102	TYUMEN	TYEnergo	CPP-B	0	0	0.0%	NA
103	TYUMEN	TYEnergo	GT	0	0	0.0%	NA
104	TYUMEN	TYEnergo	CPP-C	0	0	0.0%	NA
105	TYUMEN	TYEnergo	Other	0	0	0.0%	NA
106	TYUMEN	TYEnergo	Other	0	0	0.0%	NA
107	TYUMEN	TYEnergo	Other	0	0	0.0%	NA
108	TYUMEN	TYEnergo	Other	0	0	0.0%	NA
109	TYUMEN	MINATOM	LM	0	0	0.0%	NA
110	TYUMEN	MINATOM	LM	0	0	0.0%	NA
111	TYUMEN	MINATOM	LM	0	0	0.0%	NA
112	FAREAST	FEEnergo	HPP	0	5760	100.0%	137,266,800
113	FAREAST	MINATOM	NPP	0	0	0.0%	NA
114	FAREAST	FEEnergo	CHP-A	0	0	0.0%	NA
115	FAREAST	FEEnergo	CHP-B	0	0	0.0%	NA
116	FAREAST	FEEnergo	CHP-C	0	5760	100.0%	137,266,800
117	FAREAST	FEEnergo	CPP-A	0	0	0.0%	NA
118	FAREAST	FEEnergo	CPP-B	0	0	0.0%	NA
119	FAREAST	FEEnergo	GT	0	0	0.0%	NA
120	FAREAST	FEEnergo	CPP-C	0	4490.4	78.0%	137,266,800
121	FAREAST	FEEnergo	Other	0	0	0.0%	NA
122	FAREAST	FEEnergo	Other	0	0	0.0%	NA
123	FAREAST	FEEnergo	Other	0	0	0.0%	NA
124	FAREAST	FEEnergo	Other	0	0	0.0%	NA
125	FAREAST	FEEnergo	Other	0	0	0.0%	NA
126	FAREAST	FEEnergo	Other	0	0	0.0%	NA
127	FAREAST	FEEnergo	Other	0	0	0.0%	NA
128	FAREAST	LM & Deficit	LM	0	0	0.0%	NA
129	FAREAST	LM & Deficit	LM	0	0	0.0%	NA
130	FAREAST	LM & Deficit	LM	0	0	0.0%	NA

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AGGREGATE RESULTS

DETAILED OUTPUT AREA

Scenario: ERI1995

ERI 1995 Scenario, 07/19/94

PRESS "Alt/M" FOR MENU

(REPMOFF) Russian Electric Power Market

Operational & Fianancial Framework

ERI1995

AGGREGATE DETAILED OUTPUT

Plant No.	Zone	Company	Plant	Variable Costs (R/MWh)	Total MWh Generated	Energy Earnings	Uplift Earnings	Aggregate Fixed Costs	Income (Rubles)
0	NWEST	NWEnergo	HPP	0	16,704,000	167,040,000	0	0	167,040,000
1	NWEST	MINATOM	NPP	0	33,408,000	334,080,000	0	0	334,080,000
2	NWEST	NWEnergo	CHP-A	(194,832,000)	14,400,000	338,832,064	0	0	144,000,064
3	NWEST	NWEnergo	CHP-B	0	0	0	0	0	0
4	NWEST	NWEnergo	CHP-C	(127,920,672)	9,440,640	222,327,072	0	0	94,406,400
5	NWEST	NWEnergo	CPP-A	(6,385,361)	296,442	9,349,781	0	0	2,964,420
6	NWEST	NWEnergo	CPP-B	0	0	0	0	0	0
7	NWEST	NWEnergo	GT	0	0	0	0	0	0
8	NWEST	NWEnergo	CPP-C	0	1,152,000	11,520,000	0	0	11,520,000
9	NWEST	NWEnergo	Other	0	0	0	0	0	0
10	NWEST	NWEnergo	Other	0	0	0	0	0	0
11	NWEST	NWEnergo	Other	0	0	0	0	0	0
12	NWEST	NWEnergo	Other	0	0	0	0	0	0
13	NWEST	LM & Deficit	LM	0	0	0	0	0	0
14	NWEST	LM & Deficit	LM	0	0	0	0	0	0
15	NWEST	LM & Deficit	LM	0	0	0	0	0	0
16	CENTER	CNEnergo	HPP	0	28,224,000	282,240,000	0	0	282,240,000
17	CENTER	MINATOM	NPP	0	73,728,000	737,280,000	0	0	737,280,000
18	CENTER	CNEnergo	CHP-A	(1,252,512,896)	80,755,200	2,060,064,896	0	0	807,552,000
19	CENTER	CNEnergo	CHP-B	0	0	0	0	0	0
20	CENTER	CNEnergo	CHP-C	(597,484,800)	47,232,000	1,069,805,184	0	0	472,320,384
21	CENTER	CNEnergo	CPP-A	(337,739,104)	16,694,965	504,688,768	0	0	166,949,664
22	CENTER	CNEnergo	CPP-B	0	0	0	0	0	0
23	CENTER	CNEnergo	GT	(33,925,920)	2,879,960	62,725,516	0	0	28,799,596
24	CENTER	CNEnergo	CPP-C	(229,986,000)	13,665,240	366,638,400	0	0	136,652,400
25	CENTER	CNEnergo	Other	0	0	0	0	0	0
26	CENTER	CNEnergo	Other	0	0	0	0	0	0
27	CENTER	CNEnergo	Other	0	0	0	0	0	0
28	CENTER	CNEnergo	Other	0	0	0	0	0	0
29	CENTER	LM & Deficit	LM	0	0	0	0	0	0
30	CENTER	LM & Deficit	LM	0	0	0	0	0	0
31	CENTER	LM & Deficit	LM	0	0	0	0	0	0
32	NCAUC	NCEnergo	HPP	0	17,280,000	172,800,000	0	0	172,800,000
33	NCAUC	MINATOM	NPP	0	0	0	0	0	0
34	NCAUC	NCEnergo	CHP-A	(207,826,560)	10,944,000	317,266,624	0	0	109,440,064
35	NCAUC	NCEnergo	CHP-B	0	0	0	0	0	0
36	NCAUC	NCEnergo	CHP-C	0	0	0	0	0	0
37	NCAUC	NCEnergo	CPP-A	(236,016,000)	10,728,000	343,296,000	0	0	107,280,000
38	NCAUC	NCEnergo	CPP-B	0	0	0	0	0	0
39	NCAUC	NCEnergo	GT	0	0	0	0	0	0
40	NCAUC	NCEnergo	CPP-C	(71,228,160)	3,456,000	105,788,160	0	0	34,560,000
41	NCAUC	NCEnergo	Other	0	0	0	0	0	0
42	NCAUC	NCEnergo	Other	0	0	0	0	0	0
43	NCAUC	NCEnergo	Other	0	0	0	0	0	0
44	NCAUC	NCEnergo	Other	0	0	0	0	0	0
45	NCAUC	LM & Deficit	LM	0	0	0	0	0	0
46	NCAUC	LM & Deficit	LM	0	0	0	0	0	0
47	NCAUC	LM & Deficit	LM	0	0	0	0	0	0
48	MVOLGA	MVEnergo	HPP	0	35,712,000	357,120,000	0	0	357,120,000
49	MVOLGA	MINATOM	NPP	0	23,040,000	230,400,000	0	0	230,400,000
50	MVOLGA	MVEnergo	CHP-A	(812,543,872)	53,107,448	1,343,618,048	0	0	531,074,176
51	MVOLGA	MVEnergo	CHP-B	0	0	0	0	0	0
52	MVOLGA	MVEnergo	CHP-C	(85,478,400)	8,064,000	166,118,400	0	0	80,640,000
53	MVOLGA	MVEnergo	CPP-A	(19,113,120)	936,000	28,473,120	0	0	9,360,000
54	MVOLGA	MVEnergo	CPP-B	0	0	0	0	0	0
55	MVOLGA	MVEnergo	GT	0	0	0	0	0	0
56	MVOLGA	MVEnergo	CPP-C	0	0	0	0	0	0
57	MVOLGA	MVEnergo	Other	0	0	0	0	0	0
58	MVOLGA	MVEnergo	Other	0	0	0	0	0	0
59	MVOLGA	MVEnergo	Other	0	0	0	0	0	0
60	MVOLGA	MVEnergo	Other	0	0	0	0	0	0
61	MVOLGA	LM & Deficit	LM	0	0	0	0	0	0
62	MVOLGA	LM & Deficit	LM	0	0	0	0	0	0
63	MVOLGA	LM & Deficit	LM	0	0	0	0	0	0
64	URALS	UREnergo	HPP	0	10,368,000	103,680,000	0	0	103,680,000
65	URALS	MINATOM	NPP	0	3,456,000	34,560,000	0	0	34,560,000
66	URALS	UREnergo	CHP-A	(411,540,480)	29,952,000	711,060,480	0	0	299,520,000
67	URALS	UREnergo	CHP-B	0	0	0	0	0	0
68	URALS	UREnergo	CHP-C	(366,474,240)	38,016,000	746,634,240	0	0	380,160,000
69	URALS	UREnergo	CPP-A	(473,856,608)	26,862,624	742,482,944	0	0	268,626,336
70	URALS	UREnergo	CPP-B	0	0	0	0	0	0
71	URALS	UREnergo	GT	0	0	0	0	0	0

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Scenario: ERI1995
ERI 1995 Scenario, 07/19/94
PRESS "AltM" FOR MENU

ERI1995
AGGREGATE DETAILED OUTPUT

Plant No.	Zone	Company	Plant	Variable Costs (R/MWh)	Total MWh Generated	Energy Earnings	Uplift Earnings	Aggregate Fixed Costs	Income (Rubles)
72	URALS	UREnergo	CPP-C	(342,351,360)	29,952,000	641,871,360	0	0	299,520,000
73	URALS	UREnergo	Other	0	0	0	0	0	0
74	URALS	UREnergo	Other	0	0	0	0	0	0
75	URALS	UREnergo	Other	0	0	0	0	0	0
76	URALS	UREnergo	Other	0	0	0	0	0	0
77	URALS	LM & Deficit	LM	0	0	0	0	0	0
78	URALS	LM & Deficit	LM	0	0	0	0	0	0
79	URALS	LM & Deficit	LM	0	0	0	0	0	0
80	SIBERIA	SIEnergo	HPP	0	128,448,000	1,284,480,000	0	0	1,284,480,000
81	SIBERIA	MINATOM	NPP	0	0	0	0	0	0
82	SIBERIA	SIEnergo	CHP-A	0	0	0	0	0	0
83	SIBERIA	SIEnergo	CHP-B	0	0	0	0	0	0
84	SIBERIA	SIEnergo	CHP-C	(414,311,200)	82,368,000	1,237,991,296	0	0	823,680,096
85	SIBERIA	SIEnergo	CPP-A	0	0	0	0	0	0
86	SIBERIA	SIEnergo	CPP-B	0	0	0	0	0	0
87	SIBERIA	SIEnergo	GT	0	0	0	0	0	0
88	SIBERIA	SIEnergo	CPP-C	(154,440,000)	23,400,000	388,440,000	0	0	234,000,000
89	SIBERIA	SIEnergo	Other	0	0	0	0	0	0
90	SIBERIA	SIEnergo	Other	0	0	0	0	0	0
91	SIBERIA	SIEnergo	Other	0	0	0	0	0	0
92	SIBERIA	SIEnergo	Other	0	0	0	0	0	0
93	SIBERIA	LM & Deficit	LM	0	0	0	0	0	0
94	SIBERIA	LM & Deficit	LM	0	0	0	0	0	0
95	SIBERIA	LM & Deficit	LM	0	0	0	0	0	0
96	TYUMEN	TYEnergo	HPP	0	0	0	0	0	0
97	TYUMEN	MINATOM	NPP	0	0	0	0	0	0
98	TYUMEN	TYEnergo	CHP-A	(120,377,328)	9,486,000	215,237,344	0	0	94,860,016
99	TYUMEN	TYEnergo	CHP-B	0	0	0	0	0	0
100	TYUMEN	TYEnergo	CHP-C	(231,782,416)	46,080,000	692,582,400	0	0	460,799,984
101	TYUMEN	TYEnergo	CPP-A	0	0	0	0	0	0
102	TYUMEN	TYEnergo	CPP-B	0	0	0	0	0	0
103	TYUMEN	TYEnergo	GT	0	0	0	0	0	0
104	TYUMEN	TYEnergo	CPP-C	0	0	0	0	0	0
105	TYUMEN	TYEnergo	Other	0	0	0	0	0	0
106	TYUMEN	TYEnergo	Other	0	0	0	0	0	0
107	TYUMEN	TYEnergo	Other	0	0	0	0	0	0
108	TYUMEN	TYEnergo	Other	0	0	0	0	0	0
109	TYUMEN	MINATOM	LM	0	0	0	0	0	0
110	TYUMEN	MINATOM	LM	0	0	0	0	0	0
111	TYUMEN	MINATOM	LM	0	0	0	0	0	0
112	FAREAST	FEEnergo	HPP	0	7,488,000	0	0	0	0
113	FAREAST	MINATOM	NPP	0	0	0	0	0	0
114	FAREAST	FEEnergo	CHP-A	0	0	0	0	0	0
115	FAREAST	FEEnergo	CHP-B	0	0	0	0	0	0
116	FAREAST	FEEnergo	CHP-C	(253,733,760)	16,704,000	420,773,632	0	0	167,039,872
117	FAREAST	FEEnergo	CPP-A	0	0	0	0	0	0
118	FAREAST	FEEnergo	CPP-B	0	0	0	0	0	0
119	FAREAST	FEEnergo	GT	0	0	0	0	0	0
120	FAREAST	FEEnergo	CPP-C	(279,096,320)	12,124,080	400,337,088	0	0	121,240,768
121	FAREAST	FEEnergo	Other	0	0	0	0	0	0
122	FAREAST	FEEnergo	Other	0	0	0	0	0	0
123	FAREAST	FEEnergo	Other	0	0	0	0	0	0
124	FAREAST	FEEnergo	Other	0	0	0	0	0	0
125	FAREAST	FEEnergo	Other	0	0	0	0	0	0
126	FAREAST	FEEnergo	Other	0	0	0	0	0	0
127	FAREAST	FEEnergo	Other	0	0	0	0	0	0
128	FAREAST	LM & Deficit	LM	0	0	0	0	0	0
129	FAREAST	LM & Deficit	LM	0	0	0	0	0	0
130	FAREAST	LM & Deficit	LM	0	0	0	0	0	0
			TOTAL	(7,260,956,577)	966,552,599	16,851,602,817	0	0	9,590,646,240

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PHYSICAL OUTPUTS

Scenario: ERI1995
DAY 1
ERI 1995 Scenario, 07/19/94

(REPMOFF)

RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Physical Outputs & SMP

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				Period 1	Period 2	Period 3	Period 4	Period 5	Period 6	Period 7	Period 8	Period 9
		Scenario ID		ERI1995	ERI1995	ERI1995	ERI1995	ERI1995	ERI1995	ERI1995	ERI1995	ERI1995
		Hours/Period		3	3	3	3	3	3	3	3	0
		1. Realized Plant Capacities in MW										
0	NWEST	NWEnergo	HPP	2900	2900	2900	2900	2900	2900	2900	2,900	2,900
1	NWEST	MINATOM	NPP	5800	5800	5800	5800	5800	5800	5800	5,800	5,800
2	NWEST	NWEnergo	CHP-A	2500	2500	2500	2500	2500	2500	2500	2,500	2,500
3	NWEST	NWEnergo	CHP-B	0	0	0	0	0	0	0	0	0
4	NWEST	NWEnergo	CHP-C	1900	1900	1900	1900	1900	1900	1900	1,900	1,900
5	NWEST	NWEnergo	CPP-A	1200	1200	1200	1200	1200	1200	1200	1,200	1,200
6	NWEST	NWEnergo	CPP-B	0	0	0	0	0	0	0	0	0
7	NWEST	NWEnergo	GT	0	0	0	0	0	0	0	0	0
8	NWEST	NWEnergo	CPP-C	200	200	200	200	200	200	200	200	200
9	NWEST	NWEnergo	Other	0	0	0	0	0	0	0	0	0
10	NWEST	NWEnergo	Other	0	0	0	0	0	0	0	0	0
11	NWEST	NWEnergo	Other	0	0	0	0	0	0	0	0	0
12	NWEST	NWEnergo	Other	0	0	0	0	0	0	0	0	0
13	NWEST	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
14	NWEST	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
15	NWEST	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
16	CENTER	CNEnergo	HPP	4900	4900	4900	4900	4900	4900	4900	4,900	4,900
17	CENTER	MINATOM	NPP	12800	12800	12,800	12800	12800	12800	12800	12,800	12,800
18	CENTER	CNEnergo	CHP-A	14600	14600	14600	14600	14600	14600	14600	14,600	14,600
19	CENTER	CNEnergo	CHP-B	0	0	0	0	0	0	0	0	0
20	CENTER	CNEnergo	CHP-C	8200	8200	8200	8200	8200	8200	8200	8,200	8,200
21	CENTER	CNEnergo	CPP-A	7000	7000	7000	7000	7000	7000	7000	7,000	7,000
22	CENTER	CNEnergo	CPP-B	0	0	0	0	0	0	0	0	0
23	CENTER	CNEnergo	GT	500	500	500	500	500	500	500	500	500
24	CENTER	CNEnergo	CPP-C	3300	3300	3300	3300	3300	3300	3300	3,300	3,300
25	CENTER	CNEnergo	Other	0	0	0	0	0	0	0	0	0
26	CENTER	CNEnergo	Other	0	0	0	0	0	0	0	0	0
27	CENTER	CNEnergo	Other	0	0	0	0	0	0	0	0	0
28	CENTER	CNEnergo	Other	0	0	0	0	0	0	0	0	0
29	CENTER	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
30	CENTER	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
31	CENTER	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
32	NCAUC	NCEnergo	HPP	3000	3000	3000	3000	3000	3000	3000	3,000	3,000
33	NCAUC	MINATOM	NPP	0	0	0	0	0	0	0	0	0
34	NCAUC	NCEnergo	CHP-A	1900	1900	1900	1900	1900	1900	1900	1,900	1,900
35	NCAUC	NCEnergo	CHP-B	0	0	0	0	0	0	0	0	0
36	NCAUC	NCEnergo	CHP-C	100	100	100	100	100	100	100	100	100
37	NCAUC	NCEnergo	CPP-A	3900	3900	3900	3900	3,900	3900	3900	3,900	3,900
38	NCAUC	NCEnergo	CPP-B	0	0	0	0	0	0	0	0	0
39	NCAUC	NCEnergo	GT	0	0	0	0	0	0	0	0	0
40	NCAUC	NCEnergo	CPP-C	600	600	600	600	600	600	600	600	600
41	NCAUC	NCEnergo	Other	0	0	0	0	0	0	0	0	0
42	NCAUC	NCEnergo	Other	0	0	0	0	0	0	0	0	0
43	NCAUC	NCEnergo	Other	0	0	0	0	0	0	0	0	0
44	NCAUC	NCEnergo	Other	0	0	0	0	0	0	0	0	0
45	NCAUC	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
46	NCAUC	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
47	NCAUC	LM & Deficit	LM	10000	10000	10000	10000	10000	10,000	10000	10,000	10,000
48	MVOLGA	MVEnergo	HPP	6200	6200	6200	6200	6200	6200	6200	6,200	6,200
49	MVOLGA	MINATOM	NPP	4000	4000	4000	4000	4000	4000	4000	4,000	4,000
50	MVOLGA	MVEnergo	CHP-A	9500	9500	9500	9500	9500	9500	9500	9,500	9,500
51	MVOLGA	MVEnergo	CHP-B	0	0	0	0	0	0	0	0	0
52	MVOLGA	MVEnergo	CHP-C	1400	1400	1400	1400	1400	1400	1400	1,400	1,400
53	MVOLGA	MVEnergo	CPP-A	1300	1300	1300	1300	1300	1300	1300	1,300	1,300
54	MVOLGA	MVEnergo	CPP-B	0	0	0	0	0	0	0	0	0
55	MVOLGA	MVEnergo	GT	0	0	0	0	0	0	0	0	0
56	MVOLGA	MVEnergo	CPP-C	0	0	0	0	0	0	0	0	0
57	MVOLGA	MVEnergo	Other	0	0	0	0	0	0	0	0	0
58	MVOLGA	MVEnergo	Other	0	0	0	0	0	0	0	0	0
59	MVOLGA	MVEnergo	Other	0	0	0	0	0	0	0	0	0
60	MVOLGA	MVEnergo	Other	0	0	0	0	0	0	0	0	0
61	MVOLGA	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
62	MVOLGA	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000

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63	MVOLGA	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
64	URALS	UREnergo	HPP	1800	1800	1800	1800	1800	1800	1,800	1,800	1,800
65	URALS	MINATOM	NPP	600	600	600	600	600	600	600	600	600
66	URALS	UREnergo	CHP-A	5200	5200	5200	5200	5200	5200	5,200	5,200	5,200
67	URALS	UREnergo	CHP-B	0	0	0	0	0	0	0	0	0
68	URALS	UREnergo	CHP-C	6600	6600	6600	6600	6600	6600	6,600	6,600	6,600
69	URALS	UREnergo	CPP-A	7500	7500	7500	7500	7500	7500	7,500	7,500	7,500
70	URALS	UREnergo	CPP-B	0	0	0	0	0	0	0	0	0
71	URALS	UREnergo	GT	0	0	0	0	0	0	0	0	0
72	URALS	UREnergo	CPP-C	5200	5200	5200	5200	5200	5200	5,200	5,200	5,200
73	URALS	UREnergo	Other	0	0	0	0	0	0	0	0	0
74	URALS	UREnergo	Other	0	0	0	0	0	0	0	0	0
75	URALS	UREnergo	Other	0	0	0	0	0	0	0	0	0
76	URALS	UREnergo	Other	0	0	0	0	0	0	0	0	0
77	URALS	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
78	URALS	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
79	URALS	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
80	SIBERIA	SIEnergo	HPP	22300	22300	22300	22300	22300	22300	22,300	22,300	22,300
81	SIBERIA	MINATOM	NPP	0	0	0	0	0	0	0	0	0
82	SIBERIA	SIEnergo	CHP-A	0	0	0	0	0	0	0	0	0
83	SIBERIA	SIEnergo	CHP-B	0	0	0	0	0	0	0	0	0
84	SIBERIA	SIEnergo	CHP-C	14300	14300	14300	14300	14300	14300	14,300	14,300	14,300
85	SIBERIA	SIEnergo	CPP-A	0	0	0	0	0	0	0	0	0
86	SIBERIA	SIEnergo	CPP-B	0	0	0	0	0	0	0	0	0
87	SIBERIA	SIEnergo	GT	0	0	0	0	0	0	0	0	0
88	SIBERIA	SIEnergo	CPP-C	4600	4600	4600	4600	4600	4600	4,600	4,600	4,600
89	SIBERIA	SIEnergo	Other	0	0	0	0	0	0	0	0	0
90	SIBERIA	SIEnergo	Other	0	0	0	0	0	0	0	0	0
91	SIBERIA	SIEnergo	Other	0	0	0	0	0	0	0	0	0
92	SIBERIA	SIEnergo	Other	0	0	0	0	0	0	0	0	0
93	SIBERIA	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
94	SIBERIA	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
95	SIBERIA	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
96	TYUMEN	TYEnergo	HPP	0	0	0	0	0	0	0	0	0
97	TYUMEN	MINATOM	NPP	0	0	0	0	0	0	0	0	0
98	TYUMEN	TYEnergo	CHP-A	1700	1700	1700	1700	1700	1700	1,700	1,700	1,700
99	TYUMEN	TYEnergo	CHP-B	0	0	0	0	0	0	0	0	0
100	TYUMEN	TYEnergo	CHP-C	8000	8000	8000	8000	8000	8000	8,000	8,000	8,000
101	TYUMEN	TYEnergo	CPP-A	0	0	0	0	0	0	0	0	0
102	TYUMEN	TYEnergo	CPP-B	0	0	0	0	0	0	0	0	0
103	TYUMEN	TYEnergo	GT	0	0	0	0	0	0	0	0	0
104	TYUMEN	TYEnergo	CPP-C	0	0	0	0	0	0	0	0	0
105	TYUMEN	TYEnergo	Other	0	0	0	0	0	0	0	0	0
106	TYUMEN	TYEnergo	Other	0	0	0	0	0	0	0	0	0
107	TYUMEN	TYEnergo	Other	0	0	0	0	0	0	0	0	0
108	TYUMEN	TYEnergo	Other	0	0	0	0	0	0	0	0	0
109	TYUMEN	MINATOM	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
110	TYUMEN	MINATOM	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
111	TYUMEN	MINATOM	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
112	FAREAST	FEEnergo	HPP	1300	1300	1300	1300	1300	1300	1,300	1,300	1,300
113	FAREAST	MINATOM	NPP	0	0	0	0	0	0	0	0	0
114	FAREAST	FEEnergo	CHP-A	0	0	0	0	0	0	0	0	0
115	FAREAST	FEEnergo	CHP-B	0	0	0	0	0	0	0	0	0
116	FAREAST	FEEnergo	CHP-C	2900	2900	2900	2900	2900	2900	2,900	2,900	2,900
117	FAREAST	FEEnergo	CPP-A	0	0	0	0	0	0	0	0	0
118	FAREAST	FEEnergo	CPP-B	0	0	0	0	0	0	0	0	0
119	FAREAST	FEEnergo	GT	0	0	0	0	0	0	0	0	0
120	FAREAST	FEEnergo	CPP-C	2700	2700	2700	2700	2700	2700	2,700	2,700	2,700
121	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
122	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
123	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
124	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
125	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
126	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
127	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
128	FAREAST	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
129	FAREAST	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
130	FAREAST	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
			Total	422,400	422,400	422,400	422,400	422,400	422,400	422,400	422,400	422,400

PHYSICAL OUTPUTS

Scenario:	ERI1995 DAY 1
ERI 1995 Scenario, 07/19/94	

(REPMOFF)

RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Physical Outputs & SMP

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2. Realized Demand in MW

NWEST	11,088	10,224	12,528	14,256	12,672	12,816	14,400	12,384	0
CENTER	39,424	39,424	47,104	49,664	46,592	48,640	51,200	46,080	0
NCAUC	6,935	6,840	8,455	9,025	8,455	8,645	9,500	8,645	0
MVOLGA	17,696	18,592	21,728	21,504	21,056	22,400	22,400	19,936	0
URALS	23,316	24,388	26,800	25,996	25,728	26,532	26,264	24,120	0
SIBERIA	36,256	39,964	40,788	39,552	40,376	41,200	38,316	35,844	0
TYUMEN	8,536	9,409	9,603	9,312	9,506	9,700	9,021	8,439	0
FAREAST	5,727	5,589	6,348	6,693	6,348	6,417	6,900	6,417	0
Total	148,978	154,430	173,354	176,002	170,733	176,350	178,001	161,865	0

3. Actual Demand Met in MW

NWEST	11,088	10,224	12,528	14,256	12,672	12,816	14,400	12,384	0
CENTER	39,424	39,424	47,104	49,664	46,592	48,640	51,200	46,080	0
NCAUC	6,935	6,840	8,455	9,025	8,455	8,645	9,500	8,645	0
MVOLGA	17,696	18,592	21,728	21,504	21,056	22,400	22,400	19,936	0
URALS	23,316	24,388	26,800	25,996	25,728	26,532	26,264	24,120	0
SIBERIA	36,256	39,964	40,788	39,552	40,376	41,200	38,316	35,844	0
TYUMEN	8,536	9,409	9,603	9,312	9,506	9,700	9,021	8,439	0
FAREAST	5,727	5,589	6,348	6,693	6,348	6,417	6,900	6,417	0
Total	148,978	154,430	173,354	176,002	170,733	176,350	178,001	161,865	0

4. Shortage in MW

NWEST	0	0	0	0	0	0	0	0	0
CENTER	0	0	0	0	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0	0
MVOLGA	0	0	0	0	0	0	0	0	0
URALS	0	0	0	0	0	0	0	0	0
SIBERIA	0	0	0	0	0	0	0	0	0
TYUMEN	0	0	0	0	0	0	0	0	0
FAREAST	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0

5. SMP Values in R/KWh

SMP	33.02	33.02	33.02	33.02	33.02	33.02	33.02	33.02	0.00

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6. REALIZED LINE CAPACITIES in MW

Period 1

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 2

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 3

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 4

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 5

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 6

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 7

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 8

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 9

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

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PHYSICAL OUTPUTS

Scenario:	ERI 1995
	DAY 1
ERI 1995 Scenario, 07/19/94	

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RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Physical Outputs & SMP

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7. ACTUAL LINE TRANSFER in MW

Period 1

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	0	0	1,000	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	1,278	0	0	122	0	0	0
URALS	0	0	0	0	0	0	0	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 2

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	0	0	1,000	766	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	0	0	0	3,000	0	0	0
URALS	0	0	0	0	0	0	0	0
SIBERIA	0	0	0	0	1,236	0	0	0
TYUMEN	0	0	0	0	291	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 3

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	772	0	0	0	0	0	0
CENTER	0	0	1,000	78	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	0	0	0	0	0	0	0
URALS	0	0	0	564	0	0	0	0
SIBERIA	0	0	0	0	412	0	0	0
TYUMEN	0	0	0	0	97	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 4

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	0	0	0	0	0	0	0
CENTER	1,006	0	1,000	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	1,306	0	0	0	0	0	0
URALS	0	0	0	1,800	0	0	0	0
SIBERIA	0	0	0	0	1,646	0	0	0
TYUMEN	0	0	0	0	366	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 5

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	626	0	0	0	0	0	0
CENTER	0	0	1,000	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	1,754	0	0	0	0	0	0
URALS	0	0	0	1,800	0	0	0	0
SIBERIA	0	0	0	0	824	0	0	0
TYUMEN	0	0	0	0	194	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 6

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	484	0	0	0	0	0	0
CENTER	0	0	1,000	1,000	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	0	0	0	0	0	0	0
URALS	0	0	0	369	0	0	0	0
SIBERIA	0	0	0	0	0	0	0	0
TYUMEN	0	0	0	0	0	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 7

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	0	0	0	0	0	0	0
CENTER	734	0	1,000	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	1,710	0	0	0	0	0	0
URALS	0	0	0	1,800	0	0	0	0
SIBERIA	0	0	0	0	2,684	0	0	0
TYUMEN	0	0	0	0	679	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 8

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	916	0	0	0	0	0	0
CENTER	0	0	1,000	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	2,874	0	0	0	0	0	0
URALS	0	0	0	1,800	0	0	0	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 9

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	0	0	0	0	0	0	0
CENTER	0	0	0	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	0	0	0	0	0	0	0
URALS	0	0	0	0	0	0	0	0
SIBERIA	0	0	0	0	0	0	0	0
TYUMEN	0	0	0	0	0	0	0	0
FAREAST	0	0	0	0	0	0	0	0

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PHYSICAL OUTPUTS

Scenario:	ERI1995
	DAY 2
ERI 1995 Scenario, 07/19/94	

(REPMOFF)

RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Physical Outputs & SMP

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				Period 1	Period 2	Period 3	Period 4	Period 5	Period 6	Period 7	Period 8	Period 9
		Scenario ID		ERI1995	ERI1995	ERI1995	ERI1995	ERI1995	ERI1995	ERI1995	ERI1995	ERI1995
		Hours/Period		3	3	3	3	3	3	3	3	0
1. Realized Plant Capacities in MW												
0	NWEST	NWEnergo	HPP	2900	2900	2900	2900	2900	2900	2900	2,900	2,900
1	NWEST	MINATOM	NPP	5800	5800	5800	5800	5800	5800	5800	5,800	5,800
2	NWEST	NWEnergo	CHP-A	2500	2500	2500	2500	2500	2500	2500	2,500	2,500
3	NWEST	NWEnergo	CHP-B	0	0	0	0	0	0	0	0	0
4	NWEST	NWEnergo	CHP-C	1900	1900	1900	1900	1900	1900	1900	1,900	1,900
5	NWEST	NWEnergo	CPP-A	1200	1200	1200	1200	1200	1200	1200	1,200	1,200
6	NWEST	NWEnergo	CPP-B	0	0	0	0	0	0	0	0	0
7	NWEST	NWEnergo	GT	0	0	0	0	0	0	0	0	0
8	NWEST	NWEnergo	CPP-C	200	200	200	200	200	200	200	200	200
9	NWEST	NWEnergo	Other	0	0	0	0	0	0	0	0	0
10	NWEST	NWEnergo	Other	0	0	0	0	0	0	0	0	0
11	NWEST	NWEnergo	Other	0	0	0	0	0	0	0	0	0
12	NWEST	NWEnergo	Other	0	0	0	0	0	0	0	0	0
13	NWEST	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
14	NWEST	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
15	NWEST	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
16	CENTER	CNEnergo	HPP	4900	4900	4900	4900	4900	4900	4900	4,900	4,900
17	CENTER	MINATOM	NPP	12800	12800	12,800	12800	12800	12800	12800	12,800	12,800
18	CENTER	CNEnergo	CHP-A	14600	14600	14600	14600	14600	14600	14600	14,600	14,600
19	CENTER	CNEnergo	CHP-B	0	0	0	0	0	0	0	0	0
20	CENTER	CNEnergo	CHP-C	8200	8200	8200	8200	8200	8200	8200	8,200	8,200
21	CENTER	CNEnergo	CPP-A	7000	7000	7000	7000	7000	7000	7000	7,000	7,000
22	CENTER	CNEnergo	CPP-B	0	0	0	0	0	0	0	0	0
23	CENTER	CNEnergo	GT	500	500	500	500	500	500	500	500	500
24	CENTER	CNEnergo	CPP-C	3300	3300	3300	3300	3300	3300	3300	3,300	3,300
25	CENTER	CNEnergo	Other	0	0	0	0	0	0	0	0	0
26	CENTER	CNEnergo	Other	0	0	0	0	0	0	0	0	0
27	CENTER	CNEnergo	Other	0	0	0	0	0	0	0	0	0
28	CENTER	CNEnergo	Other	0	0	0	0	0	0	0	0	0
29	CENTER	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
30	CENTER	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
31	CENTER	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
32	NCAUC	NCEnergo	HPP	3000	3000	3000	3000	3000	3000	3000	3,000	3,000
33	NCAUC	MINATOM	NPP	0	0	0	0	0	0	0	0	0
34	NCAUC	NCEnergo	CHP-A	1900	1900	1900	1900	1900	1900	1900	1,900	1,900
35	NCAUC	NCEnergo	CHP-B	0	0	0	0	0	0	0	0	0
36	NCAUC	NCEnergo	CHP-C	100	100	100	100	100	100	100	100	100
37	NCAUC	NCEnergo	CPP-A	3900	3900	3900	3900	3,900	3900	3900	3,900	3,900
38	NCAUC	NCEnergo	CPP-B	0	0	0	0	0	0	0	0	0
39	NCAUC	NCEnergo	GT	0	0	0	0	0	0	0	0	0
40	NCAUC	NCEnergo	CPP-C	600	600	600	600	600	600	600	600	600
41	NCAUC	NCEnergo	Other	0	0	0	0	0	0	0	0	0
42	NCAUC	NCEnergo	Other	0	0	0	0	0	0	0	0	0
43	NCAUC	NCEnergo	Other	0	0	0	0	0	0	0	0	0
44	NCAUC	NCEnergo	Other	0	0	0	0	0	0	0	0	0
45	NCAUC	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
46	NCAUC	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
47	NCAUC	LM & Deficit	LM	10000	10000	10000	10000	10000	10,000	10000	10,000	10,000
48	MVOLGA	MVEnergo	HPP	6200	6200	6200	6200	6200	6200	6200	6,200	6,200
49	MVOLGA	MINATOM	NPP	4000	4000	4000	4000	4000	4000	4000	4,000	4,000
50	MVOLGA	MVEnergo	CHP-A	9500	9500	9500	9500	9500	9500	9500	9,500	9,500
51	MVOLGA	MVEnergo	CHP-B	0	0	0	0	0	0	0	0	0
52	MVOLGA	MVEnergo	CHP-C	1400	1400	1400	1400	1400	1400	1400	1,400	1,400
53	MVOLGA	MVEnergo	CPP-A	1300	1300	1300	1300	1300	1300	1300	1,300	1,300
54	MVOLGA	MVEnergo	CPP-B	0	0	0	0	0	0	0	0	0
55	MVOLGA	MVEnergo	GT	0	0	0	0	0	0	0	0	0
56	MVOLGA	MVEnergo	CPP-C	0	0	0	0	0	0	0	0	0
57	MVOLGA	MVEnergo	Other	0	0	0	0	0	0	0	0	0
58	MVOLGA	MVEnergo	Other	0	0	0	0	0	0	0	0	0
59	MVOLGA	MVEnergo	Other	0	0	0	0	0	0	0	0	0
60	MVOLGA	MVEnergo	Other	0	0	0	0	0	0	0	0	0
61	MVOLGA	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
62	MVOLGA	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000

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PHYSICAL OUTPUTS

Scenario: ERI1995
DAY 2
ERI 1995 Scenario, 07/19/94

(REPMOFF)

RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Physical Outputs & SMP

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63	MVOLGA	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
64	URALS	UREnergo	HPP	1800	1800	1800	1800	1800	1800	1,800	1,800	1,800
65	URALS	MINATOM	NPP	600	600	600	600	600	600	600	600	600
66	URALS	UREnergo	CHP-A	5200	5200	5200	5200	5200	5200	5,200	5,200	5,200
67	URALS	UREnergo	CHP-B	0	0	0	0	0	0	0	0	0
68	URALS	UREnergo	CHP-C	6600	6600	6600	6600	6600	6600	6,600	6,600	6,600
69	URALS	UREnergo	CPP-A	7500	7500	7500	7500	7500	7500	7,500	7,500	7,500
70	URALS	UREnergo	CPP-B	0	0	0	0	0	0	0	0	0
71	URALS	UREnergo	GT	0	0	0	0	0	0	0	0	0
72	URALS	UREnergo	CPP-C	5200	5200	5200	5200	5200	5200	5,200	5,200	5,200
73	URALS	UREnergo	Other	0	0	0	0	0	0	0	0	0
74	URALS	UREnergo	Other	0	0	0	0	0	0	0	0	0
75	URALS	UREnergo	Other	0	0	0	0	0	0	0	0	0
76	URALS	UREnergo	Other	0	0	0	0	0	0	0	0	0
77	URALS	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
78	URALS	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
79	URALS	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
80	SIBERIA	SIEnergo	HPP	22300	22300	22300	22300	22300	22300	22,300	22,300	22,300
81	SIBERIA	MINATOM	NPP	0	0	0	0	0	0	0	0	0
82	SIBERIA	SIEnergo	CHP-A	0	0	0	0	0	0	0	0	0
83	SIBERIA	SIEnergo	CHP-B	0	0	0	0	0	0	0	0	0
84	SIBERIA	SIEnergo	CHP-C	14300	14300	14300	14300	14300	14300	14,300	14,300	14,300
85	SIBERIA	SIEnergo	CPP-A	0	0	0	0	0	0	0	0	0
86	SIBERIA	SIEnergo	CPP-B	0	0	0	0	0	0	0	0	0
87	SIBERIA	SIEnergo	GT	0	0	0	0	0	0	0	0	0
88	SIBERIA	SIEnergo	CPP-C	4600	4600	4600	4600	4600	4600	4,600	4,600	4,600
89	SIBERIA	SIEnergo	Other	0	0	0	0	0	0	0	0	0
90	SIBERIA	SIEnergo	Other	0	0	0	0	0	0	0	0	0
91	SIBERIA	SIEnergo	Other	0	0	0	0	0	0	0	0	0
92	SIBERIA	SIEnergo	Other	0	0	0	0	0	0	0	0	0
93	SIBERIA	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
94	SIBERIA	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
95	SIBERIA	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
96	TYUMEN	TYEnergo	HPP	0	0	0	0	0	0	0	0	0
97	TYUMEN	MINATOM	NPP	0	0	0	0	0	0	0	0	0
98	TYUMEN	TYEnergo	CHP-A	1700	1700	1700	1700	1700	1700	1,700	1,700	1,700
99	TYUMEN	TYEnergo	CHP-B	0	0	0	0	0	0	0	0	0
100	TYUMEN	TYEnergo	CHP-C	8000	8000	8000	8000	8000	8000	8,000	8,000	8,000
101	TYUMEN	TYEnergo	CPP-A	0	0	0	0	0	0	0	0	0
102	TYUMEN	TYEnergo	CPP-B	0	0	0	0	0	0	0	0	0
103	TYUMEN	TYEnergo	GT	0	0	0	0	0	0	0	0	0
104	TYUMEN	TYEnergo	CPP-C	0	0	0	0	0	0	0	0	0
105	TYUMEN	TYEnergo	Other	0	0	0	0	0	0	0	0	0
106	TYUMEN	TYEnergo	Other	0	0	0	0	0	0	0	0	0
107	TYUMEN	TYEnergo	Other	0	0	0	0	0	0	0	0	0
108	TYUMEN	TYEnergo	Other	0	0	0	0	0	0	0	0	0
109	TYUMEN	MINATOM	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
110	TYUMEN	MINATOM	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
111	TYUMEN	MINATOM	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
112	FAREAST	FEEnergo	HPP	1300	1300	1300	1300	1300	1300	1,300	1,300	1,300
113	FAREAST	MINATOM	NPP	0	0	0	0	0	0	0	0	0
114	FAREAST	FEEnergo	CHP-A	0	0	0	0	0	0	0	0	0
115	FAREAST	FEEnergo	CHP-B	0	0	0	0	0	0	0	0	0
116	FAREAST	FEEnergo	CHP-C	2900	2900	2900	2900	2900	2900	2,900	2,900	2,900
117	FAREAST	FEEnergo	CPP-A	0	0	0	0	0	0	0	0	0
118	FAREAST	FEEnergo	CPP-B	0	0	0	0	0	0	0	0	0
119	FAREAST	FEEnergo	GT	0	0	0	0	0	0	0	0	0
120	FAREAST	FEEnergo	CPP-C	2700	2700	2700	2700	2700	2700	2,700	2,700	2,700
121	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
122	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
123	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
124	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
125	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
126	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
127	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
128	FAREAST	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
129	FAREAST	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
130	FAREAST	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
			Total	422,400	422,400	422,400	422,400	422,400	422,400	422,400	422,400	422,400

93

2. Realized Demand in MW

NWEST	11,088	10,224	12,528	14,256	12,672	12,816	14,400	12,384	0
CENTER	39,424	39,424	47,104	49,664	46,592	48,640	51,200	46,080	0
NCAUC	6,935	6,840	8,455	9,025	8,455	8,645	9,500	8,645	0
MVOLGA	17,696	18,592	21,728	21,504	21,056	22,400	22,400	19,936	0
URALS	23,316	24,388	26,800	25,996	25,728	26,532	26,264	24,120	0
SIBERIA	36,256	39,964	40,788	39,552	40,376	41,200	38,316	35,844	0
TYUMEN	8,536	9,409	9,603	9,312	9,506	9,700	9,021	8,439	0
FAREAST	5,727	5,589	6,348	6,693	6,348	6,417	6,900	6,417	0
Total	148,978	154,430	173,354	176,002	170,733	176,350	178,001	161,865	0

3. Actual Demand Met in MW

NWEST	11,088	10,224	12,528	14,256	12,672	12,816	14,400	12,384	0
CENTER	39,424	39,424	47,104	49,664	46,592	48,640	51,200	46,080	0
NCAUC	6,935	6,840	8,455	9,025	8,455	8,645	9,500	8,645	0
MVOLGA	17,696	18,592	21,728	21,504	21,056	22,400	22,400	19,936	0
URALS	23,316	24,388	26,800	25,996	25,728	26,532	26,264	24,120	0
SIBERIA	36,256	39,964	40,788	39,552	40,376	41,200	38,316	35,844	0
TYUMEN	8,536	9,409	9,603	9,312	9,506	9,700	9,021	8,439	0
FAREAST	5,727	5,589	6,348	6,693	6,348	6,417	6,900	6,417	0
Total	148,978	154,430	173,354	176,002	170,733	176,350	178,001	161,865	0

4. Shortage in MW

NWEST	0	0	0	0	0	0	0	0	0
CENTER	0	0	0	0	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0	0
MVOLGA	0	0	0	0	0	0	0	0	0
URALS	0	0	0	0	0	0	0	0	0
SIBERIA	0	0	0	0	0	0	0	0	0
TYUMEN	0	0	0	0	0	0	0	0	0
FAREAST	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0

5. SMP Values in R/KWh

SMP	33.02	33.02	33.02	33.02	33.02	33.02	33.02	33.02	0.00

8. REALIZED LINE CAPACITIES in MW

Period 1

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 2

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 3

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 4

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 5

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 6

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 7

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 8

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 9

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

95

7. ACTUAL LINE TRANSFER in MW

Period 1

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	0	0	1,000	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	1,278	0	0	122	0	0	0
URALS	0	0	0	0	0	0	0	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 2

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	0	0	1,000	766	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	0	0	0	3,000	0	0	0
URALS	0	0	0	0	0	0	0	0
SIBERIA	0	0	0	0	1,236	0	0	0
TYUMEN	0	0	0	0	291	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 3

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	772	0	0	0	0	0	0
CENTER	0	0	1,000	78	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	0	0	0	0	0	0	0
URALS	0	0	0	584	0	0	0	0
SIBERIA	0	0	0	0	412	0	0	0
TYUMEN	0	0	0	0	97	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 4

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	0	0	0	0	0	0	0
CENTER	1,006	0	1,000	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	1,306	0	0	0	0	0	0
URALS	0	0	0	1,800	0	0	0	0
SIBERIA	0	0	0	0	1,648	0	0	0
TYUMEN	0	0	0	0	388	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 5

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	628	0	0	0	0	0	0
CENTER	0	0	1,000	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	1,754	0	0	0	0	0	0
URALS	0	0	0	1,800	0	0	0	0
SIBERIA	0	0	0	0	824	0	0	0
TYUMEN	0	0	0	0	194	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 6

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	464	0	0	0	0	0	0
CENTER	0	0	1,000	1,000	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	0	0	0	0	0	0	0
URALS	0	0	0	388	0	0	0	0
SIBERIA	0	0	0	0	0	0	0	0
TYUMEN	0	0	0	0	0	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 7

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	0	0	0	0	0	0	0
CENTER	734	0	1,000	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	1,710	0	0	0	0	0	0
URALS	0	0	0	1,800	0	0	0	0
SIBERIA	0	0	0	0	2,984	0	0	0
TYUMEN	0	0	0	0	679	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 8

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	916	0	0	0	0	0	0
CENTER	0	0	1,000	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	2,674	0	0	0	0	0	0
URALS	0	0	0	1,800	0	0	0	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 9

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	0	0	0	0	0	0	0
CENTER	0	0	0	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	0	0	0	0	0	0	0
URALS	0	0	0	0	0	0	0	0
SIBERIA	0	0	0	0	0	0	0	0
TYUMEN	0	0	0	0	0	0	0	0
FAREAST	0	0	0	0	0	0	0	0

PHYSICAL OUTPUTS

Scenario: ERI1995
DAY 3
ERI 1995 Scenario, 07/19/94

(REPMOFF)

RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Physical Outputs & SMP

C:\REPO\REPO3.WK3
21 Jul 94 15:22

				Period 1	Period 2	Period 3	Period 4	Period 5	Period 6	Period 7	Period 8	Period 9
		Scenario ID		ERI1995	ERI1995	ERI1995	ERI1995	ERI1995	ERI1995	ERI1995	ERI1995	ERI1995
		Hours/Period		3	3	3	3	3	3	3	3	0
		1. Realized Plant Capacities in MW										
0	NWEST	NWEnergo	HPP	2900	2900	2900	2900	2900	2900	2900	2,900	2,900
1	NWEST	MINATOM	NPP	5800	5800	5800	5800	5800	5800	5800	5,800	5,800
2	NWEST	NWEnergo	CHP-A	2500	2500	2500	2500	2500	2500	2500	2,500	2,500
3	NWEST	NWEnergo	CHP-B	0	0	0	0	0	0	0	0	0
4	NWEST	NWEnergo	CHP-C	1900	1900	1900	1900	1900	1900	1900	1,900	1,900
5	NWEST	NWEnergo	CPP-A	1200	1200	1200	1200	1200	1200	1200	1,200	1,200
6	NWEST	NWEnergo	CPP-B	0	0	0	0	0	0	0	0	0
7	NWEST	NWEnergo	GT	0	0	0	0	0	0	0	0	0
8	NWEST	NWEnergo	CPP-C	200	200	200	200	200	200	200	200	200
9	NWEST	NWEnergo	Other	0	0	0	0	0	0	0	0	0
10	NWEST	NWEnergo	Other	0	0	0	0	0	0	0	0	0
11	NWEST	NWEnergo	Other	0	0	0	0	0	0	0	0	0
12	NWEST	NWEnergo	Other	0	0	0	0	0	0	0	0	0
13	NWEST	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
14	NWEST	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
15	NWEST	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
16	CENTER	CNEnergo	HPP	4900	4900	4900	4900	4900	4900	4900	4,900	4,900
17	CENTER	MINATOM	NPP	12800	12800	12,800	12800	12800	12800	12800	12,800	12,800
18	CENTER	CNEnergo	CHP-A	14600	14600	14600	14600	14600	14600	14600	14,600	14,600
19	CENTER	CNEnergo	CHP-B	0	0	0	0	0	0	0	0	0
20	CENTER	CNEnergo	CHP-C	8200	8200	8200	8200	8200	8200	8200	8,200	8,200
21	CENTER	CNEnergo	CPP-A	7000	7000	7000	7000	7000	7000	7000	7,000	7,000
22	CENTER	CNEnergo	CPP-B	0	0	0	0	0	0	0	0	0
23	CENTER	CNEnergo	GT	500	500	500	500	500	500	500	500	500
24	CENTER	CNEnergo	CPP-C	3300	3300	3300	3300	3300	3300	3300	3,300	3,300
25	CENTER	CNEnergo	Other	0	0	0	0	0	0	0	0	0
26	CENTER	CNEnergo	Other	0	0	0	0	0	0	0	0	0
27	CENTER	CNEnergo	Other	0	0	0	0	0	0	0	0	0
28	CENTER	CNEnergo	Other	0	0	0	0	0	0	0	0	0
29	CENTER	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
30	CENTER	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
31	CENTER	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
32	NCAUC	NCEnergo	HPP	3000	3000	3000	3000	3000	3000	3000	3,000	3,000
33	NCAUC	MINATOM	NPP	0	0	0	0	0	0	0	0	0
34	NCAUC	NCEnergo	CHP-A	1900	1900	1900	1900	1900	1900	1900	1,900	1,900
35	NCAUC	NCEnergo	CHP-B	0	0	0	0	0	0	0	0	0
36	NCAUC	NCEnergo	CHP-C	100	100	100	100	100	100	100	100	100
37	NCAUC	NCEnergo	CPP-A	3900	3900	3900	3900	3,900	3900	3900	3,900	3,900
38	NCAUC	NCEnergo	CPP-B	0	0	0	0	0	0	0	0	0
39	NCAUC	NCEnergo	GT	0	0	0	0	0	0	0	0	0
40	NCAUC	NCEnergo	CPP-C	600	600	600	600	600	600	600	600	600
41	NCAUC	NCEnergo	Other	0	0	0	0	0	0	0	0	0
42	NCAUC	NCEnergo	Other	0	0	0	0	0	0	0	0	0
43	NCAUC	NCEnergo	Other	0	0	0	0	0	0	0	0	0
44	NCAUC	NCEnergo	Other	0	0	0	0	0	0	0	0	0
45	NCAUC	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
46	NCAUC	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10000	10,000	10,000
47	NCAUC	LM & Deficit	LM	10000	10000	10000	10000	10000	10,000	10000	10,000	10,000
48	MVOLGA	MVEnergo	HPP	6200	6200	6200	6200	6200	6200	6200	6,200	6,200
49	MVOLGA	MINATOM	NPP	4000	4000	4000	4000	4000	4000	4000	4,000	4,000
50	MVOLGA	MVEnergo	CHP-A	9500	9500	9500	9500	9500	9500	9500	9,500	9,500
51	MVOLGA	MVEnergo	CHP-B	0	0	0	0	0	0	0	0	0
52	MVOLGA	MVEnergo	CHP-C	1400	1400	1400	1400	1400	1400	1400	1,400	1,400
53	MVOLGA	MVEnergo	CPP-A	1300	1300	1300	1300	1300	1300	1300	1,300	1,300
54	MVOLGA	MVEnergo	CPP-B	0	0	0	0	0	0	0	0	0
55	MVOLGA	MVEnergo	GT	0	0	0	0	0	0	0	0	0
56	MVOLGA	MVEnergo	CPP-C	0	0	0	0	0	0	0	0	0
57	MVOLGA	MVEnergo	Other	0	0	0	0	0	0	0	0	0
58	MVOLGA	MVEnergo	Other	0	0	0	0	0	0	0	0	0
59	MVOLGA	MVEnergo	Other	0	0	0	0	0	0	0	0	0
60	MVOLGA	MVEnergo	Other	0	0	0	0	0	0	0	0	0
61	MVOLGA	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
62	MVOLGA	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000

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PHYSICAL OUTPUTS

Scenario: ERI1995
DAY 3
ERI 1995 Scenario, 07/19/94

(REPMOFF)

RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Physical Outputs & SMP

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63	MVOLGA	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
64	URALS	UREnergo	HPP	1800	1800	1800	1800	1800	1800	1,800	1,800	1,800
65	URALS	MINATOM	NPP	600	600	600	600	600	600	600	600	600
66	URALS	UREnergo	CHP-A	5200	5200	5200	5200	5200	5200	5,200	5,200	5,200
67	URALS	UREnergo	CHP-B	0	0	0	0	0	0	0	0	0
68	URALS	UREnergo	CHP-C	6600	6600	6600	6600	6600	6600	6,600	6,600	6,600
69	URALS	UREnergo	CPP-A	7500	7500	7500	7500	7500	7500	7,500	7,500	7,500
70	URALS	UREnergo	CPP-B	0	0	0	0	0	0	0	0	0
71	URALS	UREnergo	GT	0	0	0	0	0	0	0	0	0
72	URALS	UREnergo	CPP-C	5200	5200	5200	5200	5200	5200	5,200	5,200	5,200
73	URALS	UREnergo	Other	0	0	0	0	0	0	0	0	0
74	URALS	UREnergo	Other	0	0	0	0	0	0	0	0	0
75	URALS	UREnergo	Other	0	0	0	0	0	0	0	0	0
76	URALS	UREnergo	Other	0	0	0	0	0	0	0	0	0
77	URALS	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
78	URALS	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
79	URALS	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
80	SIBERIA	SIEnergo	HPP	22300	22300	22300	22300	22300	22300	22,300	22,300	22,300
81	SIBERIA	MINATOM	NPP	0	0	0	0	0	0	0	0	0
82	SIBERIA	SIEnergo	CHP-A	0	0	0	0	0	0	0	0	0
83	SIBERIA	SIEnergo	CHP-B	0	0	0	0	0	0	0	0	0
84	SIBERIA	SIEnergo	CHP-C	14300	14300	14300	14300	14300	14300	14,300	14,300	14,300
85	SIBERIA	SIEnergo	CPP-A	0	0	0	0	0	0	0	0	0
86	SIBERIA	SIEnergo	CPP-B	0	0	0	0	0	0	0	0	0
87	SIBERIA	SIEnergo	GT	0	0	0	0	0	0	0	0	0
88	SIBERIA	SIEnergo	CPP-C	4600	4600	4600	4600	4600	4600	4,600	4,600	4,600
89	SIBERIA	SIEnergo	Other	0	0	0	0	0	0	0	0	0
90	SIBERIA	SIEnergo	Other	0	0	0	0	0	0	0	0	0
91	SIBERIA	SIEnergo	Other	0	0	0	0	0	0	0	0	0
92	SIBERIA	SIEnergo	Other	0	0	0	0	0	0	0	0	0
93	SIBERIA	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
94	SIBERIA	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
95	SIBERIA	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
96	TYUMEN	TYEnergo	HPP	0	0	0	0	0	0	0	0	0
97	TYUMEN	MINATOM	NPP	0	0	0	0	0	0	0	0	0
98	TYUMEN	TYEnergo	CHP-A	1700	1700	1700	1700	1700	1700	1,700	1,700	1,700
99	TYUMEN	TYEnergo	CHP-B	0	0	0	0	0	0	0	0	0
100	TYUMEN	TYEnergo	CHP-C	8000	8000	8000	8000	8000	8000	8,000	8,000	8,000
101	TYUMEN	TYEnergo	CPP-A	0	0	0	0	0	0	0	0	0
102	TYUMEN	TYEnergo	CPP-B	0	0	0	0	0	0	0	0	0
103	TYUMEN	TYEnergo	GT	0	0	0	0	0	0	0	0	0
104	TYUMEN	TYEnergo	CPP-C	0	0	0	0	0	0	0	0	0
105	TYUMEN	TYEnergo	Other	0	0	0	0	0	0	0	0	0
106	TYUMEN	TYEnergo	Other	0	0	0	0	0	0	0	0	0
107	TYUMEN	TYEnergo	Other	0	0	0	0	0	0	0	0	0
108	TYUMEN	TYEnergo	Other	0	0	0	0	0	0	0	0	0
109	TYUMEN	MINATOM	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
110	TYUMEN	MINATOM	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
111	TYUMEN	MINATOM	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
112	FAREAST	FEEnergo	HPP	1300	1300	1300	1300	1300	1300	1,300	1,300	1,300
113	FAREAST	MINATOM	NPP	0	0	0	0	0	0	0	0	0
114	FAREAST	FEEnergo	CHP-A	0	0	0	0	0	0	0	0	0
115	FAREAST	FEEnergo	CHP-B	0	0	0	0	0	0	0	0	0
116	FAREAST	FEEnergo	CHP-C	2900	2900	2900	2900	2900	2900	2,900	2,900	2,900
117	FAREAST	FEEnergo	CPP-A	0	0	0	0	0	0	0	0	0
118	FAREAST	FEEnergo	CPP-B	0	0	0	0	0	0	0	0	0
119	FAREAST	FEEnergo	GT	0	0	0	0	0	0	0	0	0
120	FAREAST	FEEnergo	CPP-C	2700	2700	2700	2700	2700	2700	2,700	2,700	2,700
121	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
122	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
123	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
124	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
125	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
126	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
127	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	0	0
128	FAREAST	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
129	FAREAST	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
130	FAREAST	LM & Deficit	LM	10000	10000	10000	10000	10000	10000	10,000	10,000	10,000
			Total	422,400	422,400	422,400	422,400	422,400	422,400	422,400	422,400	422,400

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PHYSICAL OUTPUTS

Scenario:	ERI1995
	DAY 3
ERI 1995 Scenario, 07/19/94	

(REPMOFF)

RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Physical Outputs & SMP

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2. Realized Demand in MW

NWEST	11,088	10,224	12,528	14,256	12,672	12,816	14,400	12,384	0
CENTER	39,424	39,424	47,104	49,664	46,592	48,640	51,200	46,080	0
NCAUC	6,935	6,840	8,455	9,025	8,455	8,645	9,500	8,645	0
MVOLGA	17,696	18,592	21,728	21,504	21,056	22,400	22,400	19,936	0
URALS	23,316	24,388	26,800	25,996	25,728	26,532	26,264	24,120	0
SIBERIA	36,256	39,964	40,788	39,552	40,376	41,200	38,316	35,844	0
TYUMEN	8,536	9,409	9,603	9,312	9,506	9,700	9,021	8,439	0
FAREAST	5,727	5,589	6,348	6,693	6,348	6,417	6,900	6,417	0
Total	148,978	154,430	173,354	176,002	170,733	176,350	178,001	161,865	0

3. Actual Demand Met in MW

NWEST	11,088	10,224	12,528	14,256	12,672	12,816	14,400	12,384	0
CENTER	39,424	39,424	47,104	49,664	46,592	48,640	51,200	46,080	0
NCAUC	6,935	6,840	8,455	9,025	8,455	8,645	9,500	8,645	0
MVOLGA	17,696	18,592	21,728	21,504	21,056	22,400	22,400	19,936	0
URALS	23,316	24,388	26,800	25,996	25,728	26,532	26,264	24,120	0
SIBERIA	36,256	39,964	40,788	39,552	40,376	41,200	38,316	35,844	0
TYUMEN	8,536	9,409	9,603	9,312	9,506	9,700	9,021	8,439	0
FAREAST	5,727	5,589	6,348	6,693	6,348	6,417	6,900	6,417	0
Total	148,978	154,430	173,354	176,002	170,733	176,350	178,001	161,865	0

4. Shortage in MW

NWEST	0	0	0	0	0	0	0	0	0
CENTER	0	0	0	0	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0	0
MVOLGA	0	0	0	0	0	0	0	0	0
URALS	0	0	0	0	0	0	0	0	0
SIBERIA	0	0	0	0	0	0	0	0	0
TYUMEN	0	0	0	0	0	0	0	0	0
FAREAST	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0

5. SMP Values in R/KWh

SMP	33.02	33.02	33.02	33.02	33.02	33.02	33.02	33.02	0.00

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8. REALIZED LINE CAPACITIES in MW

Period 1

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 2

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 3

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 4

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 5

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 6

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 7

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 8

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 9

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	1,600	0	1,000	4,000	0	0	0	0
NCAUC	0	1,000	0	0	0	0	0	0
MVOLGA	0	4,000	0	0	3,000	0	0	0
URALS	0	0	0	1,800	0	3,000	1,000	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

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PHYSICAL OUTPUTS

Scenario: ERI 1996
DAY 8
ERI 1996 Scenario, 07/19/94

(REPMOFF)
RUSSIAN ELECTRIC POWER MARKET
OPERATIONAL & FINANCIAL FRAMEWORK
Physical Outputs & SMP

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7. ACTUAL LINE TRANSFER in MW

Period 1

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	0	0	1,000	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	1,278	0	0	122	0	0	0
URALS	0	0	0	0	0	0	0	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 2

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	1,600	0	0	0	0	0	0
CENTER	0	0	1,000	766	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	0	0	0	3,000	0	0	0
URALS	0	0	0	0	0	0	0	0
SIBERIA	0	0	0	0	1,236	0	0	0
TYUMEN	0	0	0	0	291	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 3

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	772	0	0	0	0	0	0
CENTER	0	0	1,000	78	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	0	0	0	0	0	0	0
URALS	0	0	0	584	0	0	0	0
SIBERIA	0	0	0	0	412	0	0	0
TYUMEN	0	0	0	0	97	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 4

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	0	0	0	0	0	0	0
CENTER	1,008	0	1,000	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	1,308	0	0	0	0	0	0
URALS	0	0	0	1,800	0	0	0	0
SIBERIA	0	0	0	0	1,648	0	0	0
TYUMEN	0	0	0	0	388	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 5

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	628	0	0	0	0	0	0
CENTER	0	0	1,000	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	1,754	0	0	0	0	0	0
URALS	0	0	0	1,800	0	0	0	0
SIBERIA	0	0	0	0	824	0	0	0
TYUMEN	0	0	0	0	194	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 6

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	484	0	0	0	0	0	0
CENTER	0	0	1,000	1,000	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	0	0	0	0	0	0	0
URALS	0	0	0	388	0	0	0	0
SIBERIA	0	0	0	0	0	0	0	0
TYUMEN	0	0	0	0	0	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 7

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	0	0	0	0	0	0	0
CENTER	724	0	1,000	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	1,710	0	0	0	0	0	0
URALS	0	0	0	1,800	0	0	0	0
SIBERIA	0	0	0	0	2,894	0	0	0
TYUMEN	0	0	0	0	679	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 8

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	916	0	0	0	0	0	0
CENTER	0	0	1,000	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	2,674	0	0	0	0	0	0
URALS	0	0	0	1,800	0	0	0	0
SIBERIA	0	0	0	0	3,000	0	0	0
TYUMEN	0	0	0	0	1,000	0	0	0
FAREAST	0	0	0	0	0	0	0	0

Period 9

	NWEST	CENTER	NCAUC	MVOLGA	URALS	SIBERIA	TYUMEN	FAREAST
NWEST	0	0	0	0	0	0	0	0
CENTER	0	0	0	0	0	0	0	0
NCAUC	0	0	0	0	0	0	0	0
MVOLGA	0	0	0	0	0	0	0	0
URALS	0	0	0	0	0	0	0	0
SIBERIA	0	0	0	0	0	0	0	0
TYUMEN	0	0	0	0	0	0	0	0
FAREAST	0	0	0	0	0	0	0	0

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Period 1:
Scenario: [redacted]
EBI1996 Scenario 07/18/94
[illegible]

Detailed Outputs for Period 1, DAY 1

MMP	33.02	Demand	182100
		Hours/Period	3

Plant No.	Zone	Company	Plant	Variable Costs	Settlement Price	Dispatch Price	Adjusted Capacity	Unconstr Sch. MW	Constr Sch. MW	Adjusted Settlement Price	Zonal Marginal Price	Energy Payments	Uplift Payments	Total Payments
0	NWEST	NWEnergo	HPP	0	10	10	2900	2900	2900	10	23.5	87000	0	87000
1	NWEST	MINATOM	NPP	0	10	10	5800	5800	5800	10	23.5	174000	0	174000
2	NWEST	NWEnergo	CHP-A	101475	23.5	23.5	2500	2500	2500	23.5	23.5	176475	0	176475
3	NWEST	NWEnergo	CHP-B	0	0	0	0	0	0	0	23.5	0	0	0
4	NWEST	NWEnergo	CHP-C	52357	23.5	23.5	1900	1900	1268	23.5	23.5	90397	0	90397
5	NWEST	NWEnergo	CPP-A	0	31.5	31.5	1200	1200	0	31.5	23.5	0	0	0
6	NWEST	NWEnergo	CPP-B	0	0	0	0	0	0	0	23.5	0	0	0
7	NWEST	NWEnergo	GT	0	0	0	0	0	0	0	23.5	0	0	0
8	NWEST	NWEnergo	CPP-C	0	10	10	200	200	200	10	23.5	6000	0	6000
9	NWEST	NWEnergo	Other	0	0	0	0	0	0	0	23.5	0	0	0
10	NWEST	NWEnergo	Other	0	0	0	0	0	0	0	23.5	0	0	0
11	NWEST	NWEnergo	Other	0	0	0	0	0	0	0	23.5	0	0	0
12	NWEST	NWEnergo	Other	0	0	0	0	0	0	0	23.5	0	0	0
13	NWEST	LM & Deficit	LM	0	0	500	10000	0	0	0	23.5	0	0	0
14	NWEST	LM & Deficit	LM	0	0	500	10000	0	0	0	23.5	0	0	0
15	NWEST	LM & Deficit	LM	0	0	500	10000	0	0	0	23.5	0	0	0
16	CENTER	CNEnergo	HPP	0	10	10	4900	4900	4900	10	25.5	147000	0	147000
17	CENTER	MINATOM	NPP	0	10	10	12800	12800	12800	10	25.5	384000	0	384000
18	CENTER	CNEnergo	CHP-A	525324	25.5	25.5	14800	14800	11290	25.5	25.5	664024	0	664024
19	CENTER	CNEnergo	CHP-B	0	0	0	0	0	0	0	25.5	0	0	0
20	CENTER	CNEnergo	CHP-C	311190	22.6	22.6	6200	6200	6200	22.6	25.5	557190	0	557190
21	CENTER	CNEnergo	CPP-A	0	30.2	30.2	7000	7000	0	30.2	25.5	0	0	0
22	CENTER	CNEnergo	CPP-B	0	0	0	0	0	0	0	25.5	0	0	0
23	CENTER	CNEnergo	GT	17670	21.8	21.8	500	500	500	21.8	25.5	32670	0	32670
24	CENTER	CNEnergo	CPP-C	0	26.8	26.8	3300	3300	0	26.8	25.5	0	0	0
25	CENTER	CNEnergo	Other	0	0	0	0	0	0	0	25.5	0	0	0
26	CENTER	CNEnergo	Other	0	0	0	0	0	0	0	25.5	0	0	0
27	CENTER	CNEnergo	Other	0	0	0	0	0	0	0	25.5	0	0	0
28	CENTER	CNEnergo	Other	0	0	0	0	0	0	0	25.5	0	0	0
29	CENTER	LM & Deficit	LM	0	0	500	10000	0	0	0	25.5	0	0	0
30	CENTER	LM & Deficit	LM	0	0	500	10000	0	0	0	25.5	0	0	0
31	CENTER	LM & Deficit	LM	0	0	500	10000	0	0	0	25.5	0	0	0
32	NCAUC	NCEnergo	HPP	0	10	10	3000	3000	3000	10	32	90000	0	90000
33	NCAUC	MINATOM	NPP	0	0	0	0	0	0	0	32	0	0	0
34	NCAUC	NCEnergo	CHP-A	108243	29	29	1900	1900	1900	29	32	165243	0	165243
35	NCAUC	NCEnergo	CHP-B	0	0	0	0	0	0	0	32	0	0	0
36	NCAUC	NCEnergo	CHP-C	0	33.5	33.5	100	0	0	33.5	32	0	0	0
37	NCAUC	NCEnergo	CPP-A	32010	32	32	3900	3900	465	32	32	46580	0	46580
38	NCAUC	NCEnergo	CPP-B	0	0	0	0	0	0	0	32	0	0	0
39	NCAUC	NCEnergo	GT	0	0	0	0	0	0	0	32	0	0	0
40	NCAUC	NCEnergo	CPP-C	37098	30.6	30.6	600	600	600	30.6	32	55098	0	55098
41	NCAUC	NCEnergo	Other	0	0	0	0	0	0	0	32	0	0	0
42	NCAUC	NCEnergo	Other	0	0	0	0	0	0	0	32	0	0	0
43	NCAUC	NCEnergo	Other	0	0	0	0	0	0	0	32	0	0	0
44	NCAUC	NCEnergo	Other	0	0	0	0	0	0	0	32	0	0	0
45	NCAUC	LM & Deficit	LM	0	0	500	10000	0	0	0	32	0	0	0
46	NCAUC	LM & Deficit	LM	0	0	500	10000	0	0	0	32	0	0	0
47	NCAUC	LM & Deficit	LM	0	0	500	10000	0	0	0	32	0	0	0
48	MVOLGA	MVEnergo	HPP	0	10	10	6200	6200	6200	10	25.3	186000	0	186000
49	MVOLGA	MINATOM	NPP	0	10	10	4000	4000	4000	10	25.3	120000	0	120000
50	MVOLGA	MVEnergo	CHP-A	344088	25.3	25.3	9600	9600	7498	25.3	25.3	588646	0	588646
51	MVOLGA	MVEnergo	CHP-B	0	0	0	0	0	0	0	25.3	0	0	0
52	MVOLGA	MVEnergo	CHP-C	44620	20.8	20.8	1400	1400	1400	20.8	25.3	86620	0	86620
53	MVOLGA	MVEnergo	CPP-A	0	30.4	30.4	1300	1300	0	30.4	25.3	0	0	0
54	MVOLGA	MVEnergo	CPP-B	0	0	0	0	0	0	0	25.3	0	0	0
55	MVOLGA	MVEnergo	GT	0	0	0	0	0	0	0	25.3	0	0	0
56	MVOLGA	MVEnergo	CPP-C	0	0	0	0	0	0	0	25.3	0	0	0
57	MVOLGA	MVEnergo	Other	0	0	0	0	0	0	0	25.3	0	0	0
58	MVOLGA	MVEnergo	Other	0	0	0	0	0	0	0	25.3	0	0	0
59	MVOLGA	MVEnergo	Other	0	0	0	0	0	0	0	25.3	0	0	0
60	MVOLGA	MVEnergo	Other	0	0	0	0	0	0	0	25.3	0	0	0
61	MVOLGA	LM & Deficit	LM	0	0	500	10000	0	0	0	25.3	0	0	0
62	MVOLGA	LM & Deficit	LM	0	0	500	10000	0	0	0	25.3	0	0	0
63	MVOLGA	LM & Deficit	LM	0	0	500	10000	0	0	0	25.3	0	0	0
64	URALS	UREnergo	HPP	0	10	10	1800	1800	1800	10	22.7	54000	0	54000
65	URALS	MINATOM	NPP	0	10	10	600	600	600	10	22.7	18000	0	18000
66	URALS	UREnergo	CHP-A	214344	22.7	22.7	5200	5200	5200	22.7	22.7	370344	0	370344
67	URALS	UREnergo	CHP-B	0	0	0	0	0	0	0	22.7	0	0	0
68	URALS	UREnergo	CHP-C	190872	19.6	19.6	6600	6600	6600	19.6	22.7	388872	0	388872
69	URALS	UREnergo	CPP-A	0	27.8	27.8	7500	7500	0	27.8	22.7	0	0	0
70	URALS	UREnergo	CPP-B	0	0	0	0	0	0	0	22.7	0	0	0
71	URALS	UREnergo	GT	0	0	0	0	0	0	0	22.7	0	0	0
72	URALS	UREnergo	CPP-C	178308	21.4	21.4	5200	5200	5200	21.4	22.7	334308	0	334308
73	URALS	UREnergo	Other	0	0	0	0	0	0	0	22.7	0	0	0
74	URALS	UREnergo	Other	0	0	0	0	0	0	0	22.7	0	0	0
75	URALS	UREnergo	Other	0	0	0	0	0	0	0	22.7	0	0	0
76	URALS	UREnergo	Other	0	0	0	0	0	0	0	22.7	0	0	0
77	URALS	LM & Deficit	LM	0	0	500	10000	0	0	0	22.7	0	0	0
78	URALS	LM & Deficit	LM	0	0	500	10000	0	0	0	22.7	0	0	0
79	URALS	LM & Deficit	LM	0	0	500	10000	0	0	0	22.7	0	0	0
80	SIBERIA	SIEnergo	HPP	0	10	10	22300	22300	22300	10	16.8	669000	0	669000
81	SIBERIA	MINATOM	NPP	0	0	0	0	0	0	0	16.8	0	0	0
82	SIBERIA	SIEnergo	CHP-A	0	0	0	0	0	0	0	16.8	0	0	0
83	SIBERIA	SIEnergo	CHP-B	0	0	0	0	0	0	0	16.8	0	0	0
84	SIBERIA	SIEnergo	CHP-C	215787	15	15	14300	14300	14300	15	16.8	644787	0	644787
85	SIBERIA	SIEnergo	CPP-A	0	0	10	0	0	0	0	16.8	0	0	0
86	SIBERIA	SIEnergo	CPP-B	0	0	10	0	0	0	0	16.8	0	0	0
87	SIBERIA	SIEnergo	GT	0	0	10	0	0	0	0	16.8	0	0	0
88	SIBERIA	SIEnergo	CPP-C	52588	16.6	16.6	4600	4600	2858	16.6	16.6	132288	0	132288
89	SIBERIA	SIEnergo	Other	0	0	0	0	0	0	0	16.8	0	0	0
90	SIBERIA	SIEnergo	Other	0	0	0	0	0	0	0	16.8	0	0	0
91	SIBERIA	SIEnergo	Other	0	0	0	0	0	0	0	16.8	0	0	0
92	SIBERIA	SIEnergo	Other	0	0	0	0	0	0	0	16.8	0	0	0
93	SIBERIA	LM & Deficit	LM	0	0	500	10000	0	0	0	16.8	0	0	0
94	SIBERIA	LM & Deficit	LM	0	0	500	10000	0	0	0	16.8	0	0	0
95	SIBERIA	LM & Deficit	LM	0	0	500	10000	0	0	0	16.8	0	0	0
96	TYUMEN	TYEnergo	HPP	0	0	0	0	0	0	0	22.7	0	0	0
97	TYUMEN	MINATOM	NPP	0	0	0	0	0	0	0	22.7	0	0	0
98	TYUMEN	TYEnergo	CHP-A	59478	22.7	22.7	1700	1700	1538	22.7	22.7	104658	0	104658
99	TYUMEN	TYEnergo	CHP-B	0	0	0	0	0	0	0	22.7	0	0	0
100	TYUMEN	TYEnergo	CHP-C	120720	15	15	6000	6000	6000	15	22.7	380720	0	380720
101	TYUMEN	TYEnergo	CPP-A	0	0	0	0	0	0	0	22.7	0	0	0
102	TYUMEN	TYEnergo	CPP-B	0	0	0	0	0	0	0	22.7	0	0	0
103	TYUMEN	TYEnergo	GT	0	0	0	0	0	0	0	22.7	0	0	0
104	TYUMEN	TYEnergo	CPP-C	0	0	0	0	0	0	0	22.7	0	0	0
105	TYUMEN	TYEnergo	Other	0	0	0	0	0	0	0	22.7	0	0	0
106	TYUMEN	TYEnergo	Other	0	0	0	0	0	0	0	22.7	0	0	0
107	TYUMEN	TYEnergo	Other	0	0	0	0	0	0	0	22.7	0	0	0
108	TYUMEN	TYEnergo	Other	0	0	0	0	0	0	0	22.7	0	0	0
109	TYUMEN	MINATOM	LM	0	0	500	10000	0	0	0	22.7	0	0	0
110	TYUMEN	MINATOM	LM	0	0	500	10000	0	0	0	22.7	0	0	0
111	TYUMEN	MINATOM	LM	0	0	500	10000	0	0	0	22.7	0	0	0
112	FAREAST	FEEnergo	HPP	0	0	10	1300	1300	1300	0	33	0	0	0
113	FAREAST	MINATOM	NPP	0	0	0	0	0	0	0	33	0	0	0
114	FAREAST	FEEnergo	CHP-A	0	0	0	0	0	0	0	33	0	0	0
115	FAREAST	FEEnergo	CHP-B	0	0	0	0	0	0	0	33	0	0	0
116	FAREAST	FEEnergo	CHP-C	132153	25.2	25.2	2900	2900	2900	25.2	33	219153	0	219153
117	FAREAST	FEEnergo	CPP-A	0	0	0	0	0	0	0	33	0	0	0
118	FAREAST	FEEnergo	CPP-B	0	0	0	0	0	0	0	33	0	0	0
119	FAREAST	FEEnergo	GT	0	0	0	0	0	0	0	33	0	0	0
120	FAREAST	FEEnergo	CPP-C	105466	33	33	2700	2600	1527	33	33	151286	0	151286
121	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	33	0	0	0
122	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	33	0	0	0
123	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	33	0	0	0
124	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	33	0	0	0
125	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	33	0	0	0
126	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	33	0	0	0
127	FAREAST	FEEnergo	Other	0	0	0	0	0	0	0	33	0	0	0
128	FAREAST	LM & Deficit	LM	0	0	500	10000	0	0	0	33	0	0	0
129	FAREAST	LM & Deficit	LM	0	0	500	10000	0	0	0	33	0	0	0
130	FAREAST	LM & Deficit	LM	0	0	500	10000	0	0	0	33	0	0	0
						TOTAL		182,100	149,378		3,338	7,284,987	0	7,284,987

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APPENDIX G

Sample Detailed Output

The following is a sample detailed output produced by the model using input data described earlier. This sample output is for Period 1 of DAY 1 and for Type A market structure. Detailed outputs for all the periods of all the days are similar to this sample output.