Krasnodar GRES Project

Final Feasibility Report
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EXECUTIVE SUMMARY

The purpose of this Final Feasibility Report for the Krasnodar GRES project is to provide technical, financial and management information to enable decisions by the Project Ownership Group to be made to support project implementation. The Final Feasibility Report will be used by financial institutions (The World Bank) for appraisal of the Krasnodar GRES project. Information and recommendations in this report provide a basis for moving forward to form the proposed project company, Kuban GRES, finalize the bidding documents and complete other documentation to support the World Bank loan process.

Kuban GRES consists of the following organizations, with a preliminary distribution of shares as indicated below:

	Optional	Option 2
• RAO EES Rossii	34-37%	28%
• AO KubanEnergo	18-20%	14%
• RAO Gasprom	25%	20%
• Unified Electric Energy Complex Corporation	10%	8%
• AO Energo Machine-Building Corporation	8-10%	8%
• Potential Foreign Investor (Amoco)	0%	20-22%

Formal agreements for participation in the project are not in place yet, and the respective equity contributions of each member have not been finalized.

The proposed Krasnodar GRES project is a 900 MW combined cycle power plant to be built at the Mostovskoy site. The site and plant design will support expansion to 1,350 MW. Procurement of equipment and construction services will be done using multiple bid packages with management of project implementation provided by Kuban GRES and its engineering consultants. Assuming award of the combustion turbine package is made on December 1, 1996, initial plant operation at 300 MW in a simple cycle mode is projected to occur on December 1, 1998, with full operation at 900 MW projected for June 1, 2000.

The plant design uses proven technology and with the use of natural gas as a primary fuel will have minimal pollutant emissions. From a technical and environmental standpoint, the project is definitely feasible. Financial, institutional and management viability of the project will depend on the following:

- The legal formation of Kuban GRES and staffing with qualified key personnel.
- The ability to conclude a power purchase agreement at a tariff level which meets the financial expectations of the Owners, and conclude other project agreements (fuel supply, heat purchase, etc.).

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- Continued restructuring of the power sector in Russia to support a private power project and provide acceptable regulatory risks.

- Securing adequate sources of equity and debt to finance the project.

- Establishing Kuban GRES with proper management and accounting systems to ensure reliable operation of the project and necessary financial controls.

Results

Key results of the feasibility study are as follows:

- A 900 MW combined cycle power plant is necessary to meet the power deficit of the Krasnodar Krai. The Mostovskoy site provides the earliest opportunity to realize this additional generating capacity.

- The scope of the Krasnodar GRES plant will extend from the gas metering station to the 500 kV and 220 kV switchyard and include all equipment and infrastructure for power generation and heat supply. The gas pipeline up to the metering station is the responsibility of Kuban Gasprom. The electrical transmission interconnection from the on-site switchyard to the grid is the responsibility of RAO EES Rossii.

- A preliminary milestone schedule indicates that 300 MW of simple cycle capacity can be brought on line within 24 months of contract award, with the full 900 MW available within 42 months of contract award.

- The Base Case capital cost of the 900 MW Krasnodar GRES project is estimated to be $764 million, excluding the transmission system interconnection and gas pipeline. Expected sources of financing are $500 million in long term debt from The World Bank and $264 million in equity from the Project Ownership Group. Nine alternate capital structures were analyzed. As an example, Case 4 assumes $50 million of equity from foreign investors and $100 million in vendor/Export Credit Agency financing. This results in a capital cost of $798 million and a reduction in equity from the Russian Project Ownership Group to $148 million. The increase in project cost results from higher Capitalized Interest.

- A Modified Base Case Scenario was evaluated to incorporate several revisions in assumptions including elimination of the Special Tax, reduction in contingencies and duties, and limiting the use of internally generated cash to $25 million. This modified scenario reduces the risk of depending too heavily on early cash flows for successful completion of the project. Under this scenario the total project cost is $804 million, of which $500 million would be provided by the World Bank loan and $304 million in equity from the Project Ownership Group.

- The required tariff to produce a 15% return on equity in the Base Case is $0.0366/kWh (1995 US dollars) including VAT. The required tariff in the Modified Base Case is $0.0365/kWh including VAT.

- An economic model was developed to compare the economic benefits of the project to the economic costs of the project. The economic internal rate of return on the stream of net economic benefits is 20.2%.

- Development of project contracts and agreements must provide for protection against risks inherent in an undertaking of this magnitude. Potential risks examined include lower electric demand, cost overruns, delays in startup, operating risks and credit (liquidity) and tariff reform risks.

- Sale of output from the plant should be to RAO EES Rossii as manager of the wholesale power market and not directly to Kubanenergo, to minimize tariff impact on customers.

Development of a comprehensive business plan is critical to the successful and efficient implementation of the project given the diversity of potential project participants. The outline for the Kuban GRES business plan presented in this report addresses key issues for the project, including the project company's organization and proposed staffing levels, required support systems, performance indicators, management and shareholder review processes, and training needs.

Near Term Actions and Decisions Required

Key actions which need to be taken to support project implementation are:

- Legal formation of the Kuban GRES project company.

- Identification of sources of equity to meet the financing requirements of the project.

- The services of qualified consultants (engineering, financial and legal) need to be retained to support the procurement process, and World Bank loan negotiations.

Summary of Feasibility Study

An overview of the information provided in this feasibility study report is presented below.

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Need for the Project (Chapter 1)

The North Caucasus UPS has a severe electricity capacity generation deficit, with the Krasnodar Krai the region with the greatest reliance on imports. Peak demand in the year 2000 is estimated to be 9,212 MW which results in a required capacity of 10,502 MW to meet a 14 % system reserve margin. Existing effective capacity available in the winter peak period is about 8,387 MW. Current plans call for the addition of 160 MW of additional hydro capacity, 550 MW of firm capacity from a 500 kV transmission link to the Center UPS, and the replacement of aging boilers and combustion turbines at the Krasnodar CHP plant with a 450 MW combined cycle/CHP plant. Even with this new capacity, significant shortages are projected as older plants retire and the demand for electricity increases.

A Least Cost Investment Plan was performed to address the electricity needs of the North Caucasus. An assessment of the future needs for electricity and district heat was made and available supply options available within the North Caucasus and from adjacent power grids in Russia and the Ukraine were examined to identify the most economical means to meet the demand.

Primary consideration was given to new gas fired power plants at Krasnodar, Mostovskoy and Novorossiysk. The recommended expansion plan is to build a 900 MW combined cycle plant at Mostovskoy as quickly as possible, with initial operation in a simple cycle mode starting in 1998. Addition of 300 to 600 MW of simple cycle capacity at Novorossiysk in 2001 (with possible future conversion to combined cycle/CHP) also appears attractive and further study of this site is warranted.

Plant Design (Chapter 2)

The Krasnodar GRES plant is proposed to be a 900 MW combined cycle plant with future expansion to 1,350 MW. The plant is to be located at a site about 5 km from the settlement of Mostovskoy which has previously been investigated and partially developed by Kubanenergo. The plant will consist of two modular blocks of 450 MW. Each block consists of two combustion turbines of 150 MW capacity, two heat recovery steam generators and one 150 MW steam turbine generator.

The plant will use a dry cooling system to eliminate the need for withdrawal of large quantities of water from the Laba River. The primary fuel will be natural gas supplied from a new 60 km pipeline connected to the Trans-Caucasus gas pipeline, with a secondary source of gas available in underground storage caverns. Diesel fuel will be used as a backup fuel when natural gas is not available. The plant will be connected to the existing 500 kV and 220 kV transmission system.

Using modern combustion turbine technology, power plant efficiency is estimated to be 50% (on a lower heating value basis), with a plant availability of about 90%.

The power plant capital cost (equipment and construction) is estimated to be approximately $478 million (in 1995 US dollars) excluding duties, taxes and interest during construction with an additional $37 million of Owners costs for services and expenses.

Based on U.S. utility practice and taking into consideration Russian practices, the plant operating and maintenance staff is estimated to be 156 personnel. This represents an efficient organization with no overlapping or duplication of work assignments.

A detailed milestone schedule is provided identifying major engineering, procurement and construction and commissioning activities. Based on a contract award for the combustion turbines on December 1, 1996, commercial operation of the initial 300 MW of simple cycle combustion turbines is projected for December 1, 1998, with full operation of 900 MW in a combined cycle mode on June 1, 2000.

Financial and Economic Analysis (Chapter 3)

A detailed financial model for Kuban GRES has been prepared including key Financial Statements (Income Statements, Cash Flow Statement and Balance Sheet), as well as detailed projections of working capital, debt service, depreciation and capital expenditures. Alternate capital structures were analyzed to identify the impact on tariff and equity requirements. Project financing will consist of debt, primarily from the World Bank and possibly other sources, with equity from the Russian Ownership Group and possibly foreign equity contributions.

The World Bank loan is assumed to be in the amount of $500 million, with a fixed interest rate of 8%, a five year grace period for principal payments, interest capatalized during the construction period and a 17 year term from project inception. The required return on equity for Russian owners is assumed to be 15%, with higher returns (28%) required for foreign equity.

The estimated project cost, including escalation, interest during construction, working capital, duties and taxes and reserves is estimated to be $764 million. In the Base Case analysis, $500 million is provided by a World Bank loan and $264 million from Russian equity. If a one part tariff is used, the levelized tariff is $ 0.0366/kWh (in 1995 US dollars) including VAT. If a two part tariff is used the capacity charge is $ 111.78/kW/yr and the energy charge is $0.0168/kWh. These rates include VAT.

In the Modified Base Case, the total project cost is $804 million with $500 million provided by the World Bank and $304 million from Russian equity. If a one part tariff is used, the levelized tariff is $0.0365/kWh including VAT.

In order to reduce Russian equity requirements, a proposed capital structure (Case 4) includes an assumption of $50 million in foreign equity and $100 million in debt financing from equipment suppliers and foreign export-import banks. This reduces the Russian equity to $ 148 million. The project cost increases to $798 million and the one part tariff to $ 0.0392/kWh. If the gas pipeline and transmission system interconnection are included in the project cost, the Russian equity requirements increase significantlyto $473 million.

An economic analysis has been performed to facilitate efficient planning and allocation of resources in the Russian electric power sector. Economic benefits of the project include meeting electricity demand which is not served by existing capacity, and the displacement of power produced from less efficient thermal power plants. The economic costs of the project include the

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capital and operating costs. An economic internal rate of return (EIRR) is calculated from the annual stream of net economic benefits. The calculated EIRR for the project is 20.2%.

A number of the key assumptions used in the financial model represent potential areas of risk to the project owners and lenders. As described Chapter 3, the financial model was used to quantify the financial impact of certain risk factors.

The financial viability of the project is dependent on the financial capacity of the Russian Ownership Group. A financial analysis of the potential owners was performed for RAO EES Rossii and Kubanenergo based on information provided. An overview of Gasprom's financial status is limited to publicly available information. The results of this analysis indicate that Kubanenergo has not demonstrated its ability to fund a major portion of the cash equity requirements of the project. RAO EES Rossii is financially capable of participating in the Krasnodar GRES project. Since RAO EES Rossii has many other capital projects and investment opportunities a commitment to this project is needed. The financial statements of Gasprom indicate it has the financial resources to participate, and a commitment is needed. No financial information was provided during the course of this study for the Unified Electric Energy Complex Corporation or Energo Machine Building Corporation.

Institutional, Corporate and Commercial Aspects (Chapter 4)

The most viable alternative for the Krasnodar GRES project would be to structure it as a seller of power to RAO EES Rossii, the manager of the wholesale market, for resale of power to deficit utilities in the North Caucasus region, including primarily Kubanenergo. Given the size of its assets and its financial health, Kubanenergo would not on its own represent a financeable purchasing entity for the project.

Within the wholesale market, two policy options exist to either allow blending of the plant's tariff on a national basis, and thereby minimize the incremental impact of the plant on wholesale tariffs, or blend it on a regional basis in order to promote decentralization of the sectors. Both options provide significant practical and strategic advantages and disadvantages. The ultimate decision regarding regional vs national blending of the tariff rests with the Federal Energy Commission.

Development of a comprehensive business plan is critical to the successful and efficient implementation of the project given the diversity of potential project participants. An outline for the Kuban GRES business plan addresses key issues for the project, including the project company's organization and proposed staffing levels, required support systems, performance indicators, management and shareholder review processes, and training needs.

As the project is intended to be structured and implemented as an independent power production company, principles of the key agreements that would be required to finance the project have been developed. These include the shareholders agreement, the power purchase agreement, the fuel supply agreement, the heat supply agreement, and project implementation agreement. The Project Implementation Agreement outlines the additional assurances and guarantees required from the government to support financing of the project

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Operational improvement opportunities for Kubanenergo are identified in preliminary recommendations covering the following areas:

- Automation of control functions
- Automation of billing activities
- Tracking and reporting of performance indicators
- Procurement functions
- Understanding of financial concepts
- Training and personnel development

An overview of the regulatory environment of Kubanenergo was performed. At a regional regulatory level, the following general conclusions are presented:

- The regulatory environment of Kubanenergo is generally conducive to the development of Krasnodar GRES as part of the wholesale market given an established mechanism of adjusting utility tariffs to fluctuations in the utility's cost of generating or importing power,
- Regulators should adopt an approach based on protecting utility shareholders returns in order to promote additional investments, while protecting the region's ratepayers from unfair pricing practices,
- Regional regulators and the Administration should be more proactive in resolving the non-payments issue which is affecting the utility's financial viability, by empowering the utility with stricter authority to deal with non-paying customers.

At the federal level, the following preliminary recommendations are presented to improve the environment for Kuban GRES:

- Develop and approve tariff structures for new investment projects based on the concept of investment plus return,
- The utility's tariff structure should be formulated in the long term to provide greater incentives for efficient operation by promoting competition based on marginal cost (energy charge),
- Institutionalize a comprehensive set of agreements that are typically required for the financing and implementation of private power projects,
- Address uncertainties stemming from an evolving power sector structure, including issues of competition, through clear definition of the future sector structure, the role of new independent production projects, and government assurances to safeguard investor interests.

Procurement Process (Chapter 2 and 5)

All equipment and plant that is to be procured using loan funds from the World Bank must be subject to international competitive bidding. This does not preclude the use of Russian supplied equipment. In fact domestic supply is encouraged through the use of incentives in the bid evaluation process. Equipment which is procured outside of the international competitive bidding process will be evaluated by the World Bank to ensure it is of acceptable quality and has a reasonable cost.

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For a World Bank loan of $ 500 million, sufficient equipment and systems with a value equal to or in excess of this amount must be identified for international competitive bidding. If export-import bank credit is to be used to finance equipment, this would be done outside of the $ 500 million loan, and therefore additional scope for international bidding must be identified.

A two stage bidding process following World Bank guidelines is proposed. Under this approach, bids are invited on a technical basis which are complete in all respects except prices are not included. The bids are fully evaluated and those bidders which are responsive and meet the minimum qualifications requirements are invited to submit updated technical proposals with complete pricing.

Procurement of all equipment, installation and construction services will be done using a multiple bid package approach. Overall responsibility for project management including plant cost, schedule, and design, will rest with Kuban GRES. Rostovteploelectroproject (ROTEP) and an international engineering consultant will provide engineering and project management services to Kuban GRES to ensure to the project objectives and World Bank requirements are met.

The breakdown of procurement contracts is as follows:

- Combustion turbine generators and fuel supply system
- Heat recovery steam generators, steam turbine generators and auxiliary systems
- Distributed control system
- Major electrical equipment
- Switchyard
- Plant auxiliary systems
- Civil works

Environmental Assessment (Chapter 6)

A preliminary review of the Mostovskoy environment and the Krasnodar GRES plant's proposed design and operational parameters and requirements indicates that no long-term, deleterious, irreversible, or permanent environmental or health impacts would occur. In general, the plant is environmentally benign; however, there will be some short-term environmental impacts during construction, and owing to the local meteorology, there is the potential for some short-term air impacts during operation. The implementation of a variety of mitigating measures will minimize these impacts and thus render the plant environmentally acceptable.

The key potential environmental impacts and issues identified during construction and operation of the plant are:

- Land and surface water disturbances and short-term impacts due to the construction of the gas pipelines, plant drinking water supply pipeline, and the power transmission lines.

- Localized short-term degradation of ambient air quality during unfavorable meteorological conditions (temperature inversions).

These issues should not be impediments to the project as they are manageable through the use of good environmentally sensitive engineering and construction practices, development and implementation of appropriate mitigating measures and plans, and the incorporation of pollution control devices and technologies in plant, pipeline, and transmission line design, construction, and operation. Furthermore, the plant is expected to have no impact on air quality at the IUCN Biosphere Reserve, located approximately 60 kilometers from the plant.

An Environmental Impact Assessment (EIA) is being prepared and submitted for approval to the Russian regulatory agencies. The EIA must meet all requirements of the Russian Federation, the affected Russian regional and local governments, and the World Bank. The Environmental Assessment to be submitted to The World Bank will consist of the EIA for the power plant and transmission lines as well as the Gas Pipeline EIA, which has been prepared by Acres International, a consultant to Gasprom.

The EA for the World Bank was approved at the Russian federal level in January 1996. Kuban State Agricultural University (KSAU), a licensed and certified preparer of EIAs, prepared the EIA for the power plant and transmission lines. Russian Oil Initiatives, Ltd. was the lead review organization and assisted in the federal approval process.

1.0 LEAST COST INVESTMENT PLAN

A Least Cost Investment Plan was performed as Task 1 of the Krasnodar GRES project. The complete results of this effort are published in a separate report - "Least Cost Investment Plan, Krasnodar Power Generation Project", included as Volume II. A summary of the results of this report are presented below. It should be recognized that the Task 1 report was prepared early in the project, and that technical and financial information were updated during the remainder of the project as presented in this Final Feasibility Report (Volume I).

The Krasnodar Krai region of southern Russia, which is part of the North Caucasus Unified Power System (UPS), has been experiencing electricity shortages and disruptions for the past few years. A group of Russian companies composed of Kubanenergo, RAO EES Rossii, Gasprom and others (Project Owners) is planning the Krasnodar Power Generation Project. This project will involve the construction of a 1350 MW combined-cycle power station at Mostovskoy. The project owners have requested the World Bank to provide funding for the project. The purpose of this study task (Task 1) is to verify that the proposed project is required to meet the energy demands of the region. Detailed business plans and technical and environmental feasibility studies are also underway for appraisal by the World Bank.

1.1 Project Justification

The North Caucasus UPS has an acute electricity generation capacity deficit that is affecting the quality of supply. The system has a combined installed capacity of 10,557 MW, including 2,180 MW of hydro and 8,377 MW of fossil capacity. A considerable portion of this installed capacity has been de-rated due to age and deterioration in the quality of available fuel. Also, because some of the units within the region burn agricultural wastes, they are only available on a seasonal basis. This has resulted in effective available thermal capacity of 6597 MW. The maximum effective capacity (wet season) of the hydro units in North Caucasus is 1969 MW, as some of these units have also been derated. Due to seasonal effects not all of the installed hydro capacity in the region is available for meeting peak loads during the winter months; the available hydro capacity during the winter months is 1790 MW. This results in an effective system capacity of 8387 MW during winter, which is the period of the year when the annual peak load occurs.

In the past, the North Caucasus region received substantial quantities of power from Russia's Center UPS (through Ukraine) and additional power directly from generating plants within Ukraine. This interconnection became unreliable, and it is now no longer in operation. While a recent drop in consumption has provided some respite, the projected power deficit is expected to reach approximately 2,000 MW by 2000 unless new generating and transmission capacity is added to the system. This projection is based on the assumption that most of the aging existing capacity can be kept in operation for six or seven years.

The region with the greatest power deficit within the North Caucasus is the Krasnodar Kraal, which relies on imports from neighboring Energies for 60% of its electricity consumption. Because the local utility, Kubanenergo, has equipment that is in general 20 to 40 years old, the deficit will deepen further as the aging units become less reliable and must ultimately be retired.

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To address this deficit, Kubanenergo is planning to install up to 800 MW of combined cycle capacity at Krasnodar, a 300 MW combined cycle plant at Novorossiysk, and another 1,350 MW combined cycle plant at Mostovskoy.

1.2 Least-Cost Plan

The purpose of Task 1 is to evaluate the proposed projects as potential elements of a least-cost investment program to address the electricity needs of the North Caucasus UPS, with emphasis on the Krasnodar Krai. The task involved a detailed assessment of the needs for electricity and district heating in the Krasnodar Krai, and an evaluation of the supply options available within the North Caucasus UPS and from neighboring power grids in Russia and Ukraine to determine the most economical plan to alleviate the North Caucasus' power shortage.

1.2.1 Study Methodology

The evaluation of generation alternatives in a least-cost plan requires the consideration of numerous possible combinations of fuels, technologies, and sizes of generation units. A screening model was used to reduce the number of possibilities by comparing the economic performance of each resource at different levels of utilization. The screening model identifies the most likely options for in-depth consideration by a dynamic model.

A core element of the least-cost planning effort is the IPM integrated planning model, which was applied to characterize the Russian UPS as part of the Joint Electric Power Alternatives Study (JEPAS). The IPM is a least-cost planning model that uses a linear programming algorithm to select investment options and to dispatch generating resources to meet overall electricity demand and energy requirements.

Utility generating options are characterized in terms of their capital costs, operating and maintenance costs, fuel costs, heat rates, reliability, and lead times. The amount and scheduling of available power from outside the North Caucasus grid and its costs are evaluated as possible bulk power purchase options, either for economy or for firm power purchases.

Least-cost investment options are selected by the model based on the cost and performance characteristics of available options, forecasts of customer hourly consumption of electricity, and reserve margin requirements.

The most efficient use of the existing and new resources available is optimized given the resource mix, unit operating characteristics (including heat rate, forced outage rates, full and minimum load unit ratings), and operation, maintenance, and fuel costs.

The model is dynamic, that is, it develops a least-cost capacity plan for the entire forecast period at once. Decisions are made on the basis of minimizing the net present value of capital plus operating costs over the full planning horizon.

To complete the economic and financial analysis of the potential generating projects, estimates of the amount of electricity generated and its value were required. The value of electricity generated at each proposed plant has two components. First, electricity generated will displace more costly electricity generated at less efficient plants. Secondly, the proposed plant will meet some electricity requirements that would otherwise go unserved.

The IPM results provided estimates that estimate the first component of a plant's value. Specifically, IPM estimated the amount of electricity that will be generated by a particular plant and the marginal cost of electric generation displaced by the plant. However, IPM does not estimate the change in unserved energy that would result from the construction of the plant. For this purpose, the study team utilized a power reliability assessment model (P-RAM) to estimate for each hour of a planning year the loss of load probability and the amount of unserved energy.

P-RAM estimates the probability distribution of generation capacity for each hour of the planning year. This capacity probability distribution for a given hour is combined with a range of hourly load estimates that reflect load uncertainty to derive a loss of load probability. Generation capacity additions shift the capacity probability distribution, effectively reducing the probability of an outage. Based on this probabilistic approach, P-RAM estimates expected unserved energy.

1.2.2 Change Cases

Five Change Cases were evaluated to determine the impact of possible changes in the economic climate or electricity supply situation in Russia. Change Case 1 examines a Low Demand Scenario to assess the impact of a slow recovery of economic activity in Russia. Change Cases 2, 3, and 4 examine transmission system alternatives involving 500 MW of additional reinforcement, 1000 MW of additional reinforcement and re-establishment of the tie to the Ukraine. Change Case 5 examines the impact of completing the Rostov 1 Nuclear Plant by the year 2000.

1.3 Summary of Results

The North Caucasus is in need of substantial generation capacity additions in the immediate future. At this time, there is a program of Hydroelectric plant additions, totaling 160 MW, that is scheduled to bring capacity on line gradually between 1996 and 2000. In addition, a 500 kV transmission link with the Center UPS is scheduled to be completed in 1997. This will provide an additional 550 MW of firm capacity to the region. There is also a current program to replace 159 MW of aging boiler equipment and 190 MW of combustion turbines at the Krasnodar TETS site with a 400 MW CHP/Combined cycle plant. Even with these additions there is a pressing need for building new gas fired power plants.

This study has found that thermal generating capacity must be added in the North Caucasus as quickly as possible. The earliest date that new plants could be brought on line is 1998. At that time the capacity needed to maintain reliable a power supply will be 940 MW. The study has also determined the need for about 268 MW additional capacity in 1999, and for approximately 405 MW of capacity in 2000. It is therefore prudent that the proposed plan to build up to 1350 MW of combined-cycle capacity at Mostovskoy proceed on an accelerated schedule. This will be necessary to maintain a system reserve margin of 14 percent, which is the minimum for assuring reliable system operations. These additions would add a total of 1750 MW in gas fired capacity to the North Caucasus UPS during the next five years. Figure 1- 1 illustrates the need to add capacity in the region as demand grows and retirements reduce the capacity available from existing units. The data used in preparing Figure 1 -1 is presented in Table 1 - 1.

Because new and replacement capacity cannot be commissioned prior to 1998, a potential capacity shortage, ranging from 689 to1103 MW, will exist in the region through 1997. To eliminate the shortage, it will be necessary to extend the life of some of the units that have been scheduled to be retired through 1998. This is necessary because there is no practical possibility for adding new generating capacity before that year.

Regarding the location of the new capacity, Krasnodar Krai is the most appropriate area in the North Caucasus for substantial capacity additions because over 600 MW of existing capacity is scheduled to retire before the end of 2003, and the region is already heavily dependent on other regions for power. The current situation impairs the reliability of electricity service and results in excessive transmission losses. Of the three potential sites in the area, only the Mostovskoy site is available for the addition of new capacity in 1998 and, it is initially limited to the addition of simple cycle gas turbines due to construction lead time. The other two sites are expected to require an additional year or two of lead time because of the need for environmental studies to verify that they would be appropriate for building new power plants.

The Mostovskoy site offers a number of advantages, including its availability for early development. The site's only drawback is that it is not located near the major load centers in the region. The Krasnodar and Novorossiysk sites are located at major load centers, and they offer the potential for improved economic efficiency as Combined Heat and Power Plants (CHP). However, only the replacement of the older CHP units at Krasnodar TETS offers a lower cost alternative to the Mostovskoy project. Given that work is already proceeding for those replacements, the next project for the North Caucauses should be done at Mostovskoy. Recognizing the advantages of having plants located near load centers, it is likely that some smaller plant additions after 2000 will be attractive at Novorossiysk, subject to further investigation of the advantages of that site.

The following list gives a ranking of Combined Cycle options starting with the lowest cost alternative. The cost of electric power production includes the cost of new transmission facilities and gas pipelines as required for each site. (Production costs below are at 80% capacity factor):

Site	**Capacity**	**Production Cost, $/kWh**
Krasnodar CC/CHP (replacement)	400 MW	.0236
Mostovskoy CC	900 MW	.0318
Novorossiysk CC/CHP	400 MW	.0320
Novorossiysk CC	450 MW	.0320
Krasnodar CC	450 MW	.0333
Mostovskoy CC	450 MW	.0339

In the sensitivity cases, the largest change in projected total capacity additions in the North Caucasus occurred in the low demand case, Change Case 1. In this case, total capacity additions are projected to be 1,050 MW lower than in the base case. In Change Cases 2 through 4, where transmission capacity additions into the North Caucasus were analyzed, total capacity additions decline by roughly the amount of firm transmission capacity assumed. In Change Case 5, in which the Rostov Nuclear plant is assumed to be completed, total capacity additions at the Mostovskoy site decline by 940 MW, which is the size of the Rostov nuclear plant.

1.4 Recommended Project

Considering all of the above factors the following is considered to be the best approach to meeting needs for immediate capacity additions while keeping the long term costs to a minimum:

1. Krasnodar - continue with the replacement of the two existing 95 MW simple cycle units in 1997 and 1999, with conversion to 400 MW of combined cycle in 1999.

2. Mostovskoy - construct 600 MW Simple cycle addition for 1998-99 operation, with conversion to combined cycle operation in 1999 or 2000 to bring the capacity at that site to 900 MW. Allow for the possibility to add another 450 MW of combined-cycle as early as 2000 depending on the rate of demand growth during the next few years.

3. Novorossiysk - provide 300 to 600 MW simple cycle for operation in 2001, with partial conversion to combined cycle if and when CHP operation is shown to be economical or if additional base load capacity is needed.

With the exception of the already committed upgrading of the Krasnodar CHP plant, the installation of capacity at Mostovskoy was selected by the model as the next generation addition.

Considering the possible timing impacts of the events considered in the change cases, it is prudent to build the plant in two stages. The first stage, of 900 MW, should be commenced as soon as possible. The second should be 450 MW to be started when the timing for the addition becomes more certain.

Thus, the Integrated Planning Model analysis justifies the immediate commencement of the staged building of a 1350 MW combined cycle power station at Mostovskoy as next generation expansion project for the North Caucasus region.

2.0 TECHNICAL ANALYSIS

The objectives of the Technical Analysis are:

- Develop plant cost and performance information to support the financial analysis of the project;
- Prepare a technical definition of the plant, sufficient for the preparation of equipment and construction bid packages;
- Establish a bid packaging approach consistent with the World Bank procurement guidelines and Owners' needs;
- Develop a detailed implementation program for the project

2.1 Project Description

The Mostovskoy site was originally selected, in the mid-1980's, as a site suitable for construction of a nuclear plant. The plans for a nuclear plant were subsequently canceled. Site investigations were later carried out for a fossil power plant and a preliminary feasibility report was prepared in 1991 by Rostovteploelectroproject (ROTEP), the Design Institute in Rostov. This report recommended that the site be developed for a 1,350 MW combined cycle plant.

The feasibility report prepared by ROTEP provides the basis for the current project.

2.1.1 Project Site

The project site as shown on the site vicinity drawing, Figure 2.1-1 is located approximately 5 km south of the settlement of Mostovskoy. The site is in a valley with hills on both sides. Land for the project has been secured duly by Kubanenergo. The site is approximately 130 hectares of level farm land, of which the power plant will occupy approximately 68 hectares. The top 0.8 to 1.5 meters consists of excellent top soil that will require removal from the construction areas and disposal. The next 6 to 15 meters consists of large gravel mixed with clay and sand. Below the gravel there is a solid layer of water tight clay up to 150 meters deep. The water table is approximately 2 meters from the existing ground surface.

Site topography slopes towards the north and the elevation varies from 410 meters to 416 meters. There is an existing drainage ditch running through the site which carries storm water from the adjacent hilly areas on the south.

The site is approximately 2 km from the Laba river. A 110 kV overhead transmission line runs through the site. A railroad runs parallel to the site at a distance of about 1/2 km.

2.1.2 Plant Configuration

The results of the Least Cost Plan (Task 1) determined that a 900 MW combined cycle plant at the Mostovskoy site is necessary to meet the power demand of the North Caucasus. The full capacity should be in operation by the year 2000. The plant is planned to consist of two blocks of 450 MW each. Each block will consist of two combustion turbine generators, two Heat Recovery Steam Generators (HRSGs) and one steam turbine generator. Each of the three turbine generators will generate approximately 150 MW. The plant site arrangement will be laid out so that a future 450 MW block can be added for a total capacity of 1,350 MW.

The construction of the plant will be staged such that the combustion turbine units operating in a simple cycle mode will be brought on line first. The first unit of 300 MW will consist of combustion turbines 1 and 2 (CT_1 and CT_2) followed by a second unit of 300 MW consisting of CT_3 and CT_4. The second unit will follow the first after six months. The two simple cycle units will then be converted to combined cycle operation at six month intervals.

The plant will also include separate gas fired district heating steam and water boilers, and district heating heat exchangers (supplied from steam turbine extractions).

2.1.3 Site Characteristics

The Project Ownership Group has considered a number of possible locations for the proposed power station. These investigations have confirmed the suitability of the present site with respect to:

- Land ownership, availability, and access
- Topography and ground conditions
- Pollution and environmental impact
- Availability of makeup water
- Transportation of equipment
- Proximity of natural gas trunk line
- Fuel oil delivery
- Interconnection with 500 kV and 220 kV regional transmission system
- Local infrastructure

2.1.4 Site Investigations

Site investigations to assess the design considerations necessary for construction and operational requirements have previously been carried out during the Feasibility Studies conducted by ROTEP. These studies include the hydrology, geology, and meteorological aspects of the subject site.

Other investigations carried out as part of the Feasibility Study include: site access, mode of transportation, fuel supply, intake and discharge arrangements for the cooling water, and general findings of the air quality and existing sources of emissions, water quality, acoustic noise pressure levels, animal and plant kingdoms, aquatic flora and fauna, and the sociological considerations.

The results of these investigations as they apply to plant design considerations were utilized in establishing the plant design basis and in estimating the cost of the project.

2.1.5 Design Parameters and Site Conditions

The following site conditions and design parameters are noteworthy:

Geology.

The plant elevation will be located above the flood plain as described in feasibility studies conducted by ROTEP. The geological structure of the project site is composed of alluvial pebbly grounds of the Quaternary period, which are underlain by maikop clays at a depth of 10.0-14.0 meters. As a whole, the geolithological structure of the construction site is relatively uniform.

The site will be filled to raise the grade above flood level and existing drainage ditch will be relocated to prevent flooding of the site.

Based on the geotechnical investigation conducted by ROTEP, site soils will provide adequate support for shallow foundations. These shallow foundations can consist of either spread footings or structural mat. The allowable soil bearing capacity is estimated to be between 0.4 and 0.5 MPa.

Hydrology.

The hydrogeological conditions of the project construction site are characterized by a universally developed horizon of underground waters, confined to the Quaternary alluvial pebbly deposits. The depth of the acquiferous horizon is from 7.0 to 13.0 meters. However, underground water has been observed to rise up to a depth of 1.0 to 2.0 meters below the ground level.

Seismicity.

The project site is located in a seismic region. The seismicity of the project construction site, with due considerations for ground conditions, resonance phenomena and ground water level, is 7 points on the MSK-64 scale with an average repletion period of 1000 years. The maximum acceleration amplitudes are not in excess of 0.04-0.08g.

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Climate.

The region where the project will be located borders on mountainous relief 50 km south of the Great Caucasus Ridge. The surrounding relief is relatively flat, low hilly, cut by shallow ravines with flowing creeks at the bottom. The climate of the project region is temperate-continental. The proximity of the Black Sea and high ranges of the Major Caucasus produce considerable effects on the general atmospheric circulation. With active inflow of cold the absolute minimum air temperature in winter may reach minus 36-38 deg. C, while in warm weather it reaches plus 18-20 deg. C. Summer is hot, dry and long (from May to September). The absolute air temperature may reach plus 40-45 deg. C. The relative humidity ranges from 69% to 82%. Average yearly precipitation is about 900mm.

Wind.

The average wind velocities, at different altitudes above the earth surface, are depicted in the table below:

Altitude (meters)	10	20	40	50	100	150	200	300	400	500
Wind Vel. (Meters per second)	1.9	2.8	3.5	3.5	3.8	3.9	4.0	4.3	4.5	4.5

Atmospheric Pressure.

The average atmospheric pressure at the site level is 963.5 millibars.

Water Source.

A possible source of process water for the project site is the Laba River, the largest tributary of the Kuban River. Its water shed area consists of 12500 square kilometers. The section of water intake by the power plant is 3400 square kilometers. The bottom of the water intake by the power plant is pebbly and the river mouth is sandy. The highest monthly water temperature in the Laba River near the project site intake has measured from 3.8 to 18.2 deg. C. The lowest monthly water temperature, for the same period, ranged from 0.0 to 15.7 deg. C. The average annual water discharge in the Laba River in the Krasnodar power plant intake section is 83.1 cubic meters per second.

A second source of process water is on-site artesian wells. The project utilizes a dry cooling system, so makeup water requirements are mainly for HRSG blowdown. This means the water demand is relatively modest, about 120 m^3/hr. It is believed that the ground water and underground sources can supply the necessary quantity. The use of artesian well water would eliminate the environmental impact of drawing water from the river. The use of on-site wells for process water makeup is recommended.

Water wells will be formed in a water bearing gravel layer overlaying the impervious clay layer. It is recommended that test wells be drilled at the project site to establish the quantity and quality of the subsurface water. The information obtained from the test wells will determine the appropriate cost for drilling of production wells, pumping equipment and water treatment. As a minimum the exploratory test wells should include the following requirements:

1. Driller's log describing the various soil/rock stratum encountered during the well drilling.
2. Geophysical logging of the test hole including natural gamma ray, spontaneous potential and electrical resistivity.
3. Yield of the well (m^3/hour) determined based on 24 hours constant rate pumping test of the well.
4. Well water must be analyzed to determine the quality of the water.

Fuel.

The plant will be fueled by natural gas, which will be piped from an existing trunk line 60 km away. The trunk line is owned by Gazprom. A secondary source of natural gas is from underground storage caverns. The gas line pressure is 5.5 megapascals (MPa). The pipe line will be sized for a 1350 MW plant taking into consideration the future plant expansion. Diesel oil will be utilized for not more than eight (8) days per year as a back-up fuel. A gas distribution station owned by Gasprom will be located 400 m from the site.

Electric Transmission.

The plant will be connected to the existing 220 kV and 500 kV transmission systems in the North Caucasus Region. New transmission lines will be constructed for this purpose. The existing transmission lines running through the site will be rerouted.

Design Criteria

The design criteria for the plant will conform to the International Standards acceptable to the World Bank. Environmental considerations will ensure that air quality, thermal discharge and wastewater effluent quality are in compliance with World Bank and Russian regulatory requirements.

Plant equipment will be specified to be in compliance with the internationally acceptable codes and standards. Plant construction will conform to Russian standards. In addition, construction will be in compliance with any requirements imposed by the manufacturers of internationally supplied equipment for compatibility.

2.2 Plant Design

2.2.1 Combined Cycle Power Plant

The Krasnodar GRES at Mostovskoy is to be a combined cycle plant of approximately 900 MW capacity (two modules of 450 MW each) with provision for a future expansion to 1350 MW. The actual plant capacity will be determined by the capacity of the combustion turbine generators selected through international competitive bidding. A conceptual plant layout is shown on Figure 2.2-1. The main building will house the four combustion turbine generators, the four HRSG's and the two steam turbine generators, all with their respective auxiliaries and the electrical rooms. Housed in the main building are also the deaerators and the feed pumps. A common control room will be utilized for both units. A representative layout of major equipment is shown on Figure 2.2-2.

Combustion turbines with outputs ranging between 135 MW and 170 MW and manufactured by companies, such as, ABB, Westinghouse, General Electric, and Siemens were studied for this project.

The combustion turbine units will be furnished complete with all accessories and auxiliary systems required for start-up and generating capability for combined cycle operation. The combustion turbine units will include dual fuel firing systems, air intake system including a filter system, and best available technology for NOx control utilizing dry Low-NOx combustors.

The generators will be synchronous machines operating at (Later) kV, 50 Hz and a power factor capability in the range of 0.80 (lagging) to 0.9 (leading). The generator cooling medium may be air or hydrogen. Each generator will be capable of delivering the output of the turbine over its full operating range.

The exhaust gas from each combustion turbine will be routed to an individual HRSG. Each HRSG will be a multi-pressure design. High pressure and intermediate pressure steam will be produced. The intermediate pressure steam will be reheated in the HRSG. The high pressure and intermediate pressure steam from two HRSG's will be routed to one steam turbine generator. It is assumed that steam injection or water injection will not be necessary for NOx control.

Steam Turbine extractions will supply steam to the district heating heat exchangers. The heat will be transferred to the district heat hot water system. Condensed steam will be returned to the HRSG condensate cycle.

The four HRSG's, each of which will be provided with a metal by-pass stack, will discharge into a common concrete stack, 150 meter high and 15 meter in diameter. The conceptual plant layout shows the power transformers and the switchyard located north of the main building. Also shown are a switchyard control building and a local cafeteria. East of this building are located the Administration Building and a large cafeteria.

A flow diagram for the main steam system is shown in Figure 2.2-3a. The condensate and feedwater system is shown in Figure 2.2-3b.

A natural gas control station will be installed downstream of the reducing station to maintain the necessary pressure required by the combustion turbines. The natural gas control station, the repair and maintenance shop, the warehouse, and other necessary buildings to support plant operations, including a 25 car garage, are located south of the air cooled condensers. Separated from the gas control station, in a southern direction, are located the combustion turbine fuel oil tanks, mazut storage tanks for the start up and the heating boiler house (for district heating), and the fire stations.

In case of natural gas interruption the combustion turbines will operate with fuel oil for up to 8 days a year. Combustion turbine fuel storage tanks will be provided with adequate capacity to store fuel for three (3) days operation. A fuel unloading facility will be provided close to the fuel tanks. Combustion turbine fuel will be transported to the power plant by railway cars. The unloading facility will have a capacity to unload eight rail cars. The emergency fuel storage facilities will include a pump house, two (2) tanks for the start up and heating boiler house and two (2) combustion turbine fuel tanks.

An intake structure, with pumps at the river or on-site wells, will provide make-up water for the plant. Make-up water equipment, including the chemical storage tanks and the neutralization tanks, will also be utilized. A service water/fire water tank will be provided to level the peak demands for water.

Demineralized water, obtained from chemically treating raw water, will be utilized for the HRSG's. Two demineralized water storage tanks will be provided.

As the heat sink, each power block will utilize one air cooled condenser or dry cooling tower. The air cooled condensers are located adjacent and south of the main building. Steam from the turbine exhaust will flow via steam ducts to the air cooled condensers where it will be condensed by cooling air fans.

The selection of the dry-type cooling system is mandated by the limitations placed by Russian regulatory authorities on the use of water from the Laba River and also by the concerns raised, by the public and environmental commission, in regard to the fog and plume associated with a wet cooling tower.

A waste water treatment system, which will include oil/mazut/water separators, and packaged sewage treatment system, will treat wastewater before it is discharged into the waste water stream. The water treatment building will be located adjacent to the air cooled condenser area.

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2.2.2 District Heat

Each steam turbine will be capable of providing a maximum of 50 giga calories per hour of extraction steam for district heat to the settlement located near the plant.
A set of water and steam boilers, located next to the main building will provide district heat during construction. They will also, provide startup steam to the combined cycle plant after the plant is operational.

The extraction steam from each steam turbine will pass through a set of closed heat exchangers to provide district heat water and hot water supply. Extraction steam will be cooled and condensed in the shell side. Each set of heaters will be capable of meeting the maximum design requirement for district heat. Condensed steam will be returned to condensate cycle.

2.2.3 Facilities

The main power plant building superstructure will be either structural steel frame or reinforced concrete frame construction supported on reinforced concrete spread footings. The exterior wall will be insulated metal panel or precast concrete panels.

All equipment will be supported on separate reinforced concrete foundations. The foundations for the rotary equipment such as combustion turbine generator, steam turbine generator, boiler feed pumps will be designed for dynamic loads.

All structures and buildings will be designed to Russian Standards or equivalent International Standards. All design loads (live loads, wind loads, seismic loads) will be considered in accordance with the Russian Standards.

The facility will include the following major auxiliary buildings: administration building, maintenance building, water treatment building, warehouse, cafeteria, fire station, and other miscellaneous buildings.

All auxiliary buildings will be constructed of structural steel or reinforced concrete or precast concrete or combination thereof.

A railroad track will be provided for the delivery of the equipment and materials during construction and major maintenance, and for fuel deliveries during the plant operation.

All major plant access roads will be paved with asphalt concrete and all secondary roads will be surfaced with crusted stone.

All disturbed areas will be seeded and landscaped to minimize soil erosion and to provide aesthetics.

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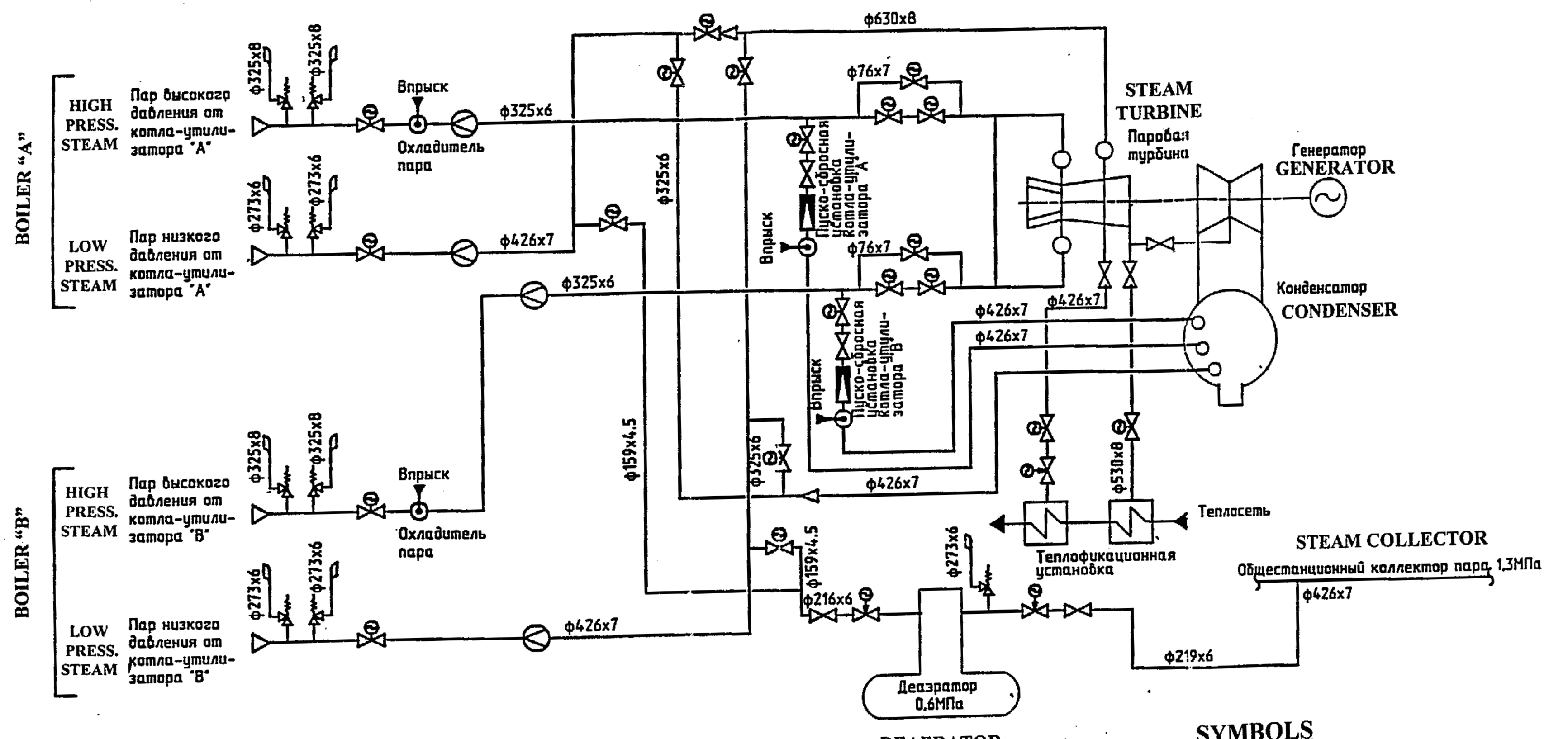
Принципиальная схема паропроводов ПГУ-450. Краснодарская ГРЭС



Трубопроводы пара высокого давления (ф325х26 и ф76х7) выполняются из легированной стали, остальные - из углеродистой стали

FIGURE NO. 2.2-3a
HIGH PRESSURE STEAM DISTRIBUTION

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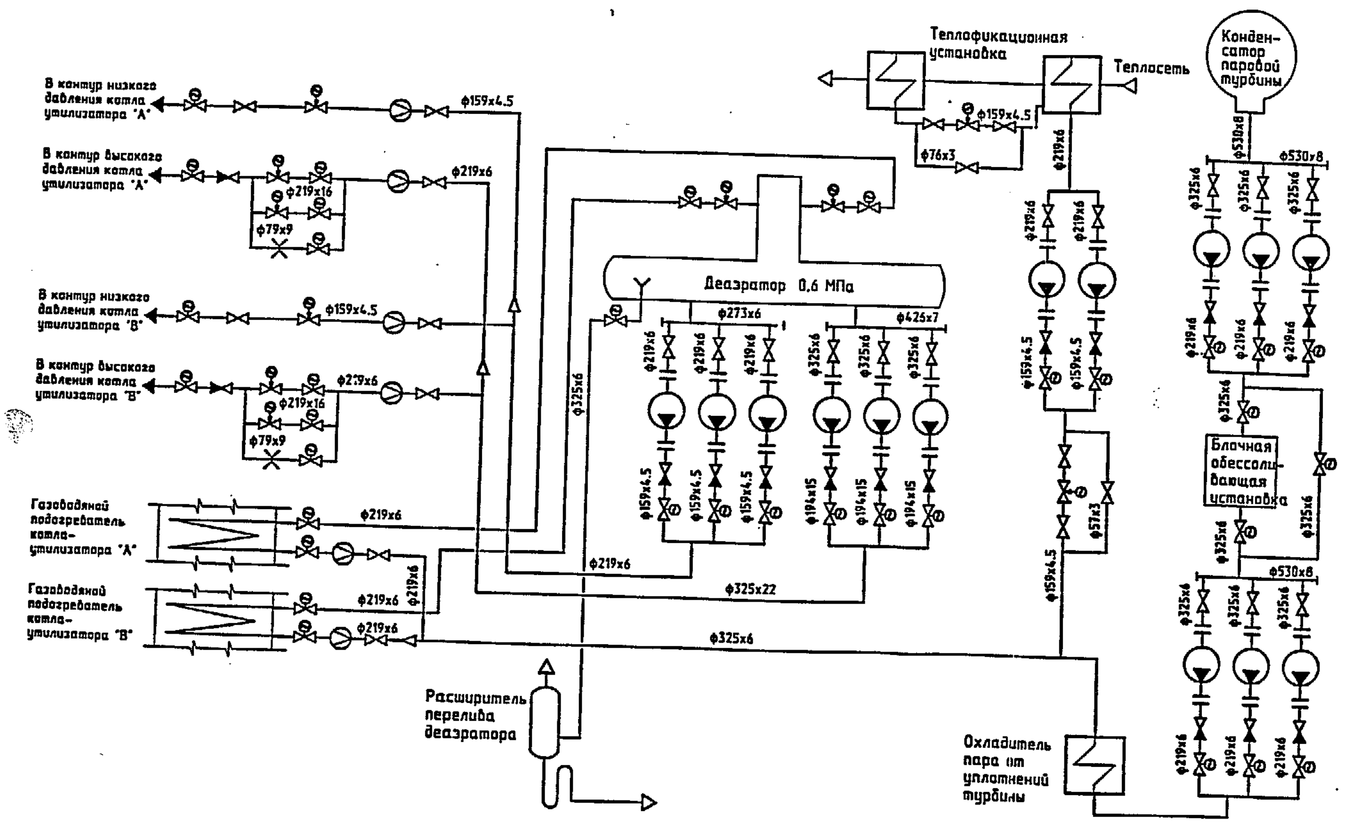
Принципиальная схема трубопроводов конденсата и питательной воды
ПГУ 450 Краснодарской ГРЭС



Перечень оборудования

NN поз	Наименование оборудования	Тип	Техническая характеристика	Кол.	Примеч.
1	2	3	4	5	6
1	Конденсатный насос первого подъема Condensate Pump - First Stage	1КсВ315-80	Н=80м; Q=315 м³/ч	3	
2	Конденсатный насос второго подъема Condensate Pump - Second Stage	1КсВ315-80	Н=80м; Q=315 м³/ч	3	
3	Конденсатный насос подогревателей теплосети Condensate Pump - F.W. Heaters	1КсВ125-140	Н=140м; Q=125м³/ч	2	
4	Питательный насос высокого давления Feed Pump - HP	ПЭ-270-150	Н=1500м;Q=270м³/ч	3	
5	Питательный насос низкого давления Feed Pump - LP	1КсВ125-140	Н=140м; Q=125м³/ч	3	

Все трубопроводы и арматура выполняются из углеродистой стали

Условные обозначения

- — задвижка Valve
- — задвижка с электроприводом Electrically-driven Valve
- — регулирующий клапан Regulator
- — предохранительный клапан Safety Valve
- — измерительная диафрагма Venturi
- — шайба дроссельная

FIGURE NO. 2.2-3b
CONDENSATE AND FEEDWATER SYSTEMS

BEST AVAILABLE COPY

A peripheral security fence will be provided and access to the project site will be controlled at main gate.

2.2.4 Drainage and Flood Control

The project site will be raised above the flood level using borrowed structural fill material. The existing drainage ditch will be relocated around the project site to prevent any possibility of the flooding. The relocated drainage ditch will be a concrete lined canal.

The project site will be provided with storm drainage system. The storm drainage system will consist of catch basins, storm sewers and open drainage ditches. All storm water from the site will be collected in a settlement basin prior to discharge into natural waterways.

2.2.5 Gas Pipeline

A new natural gas pipeline, 60 km in length and 700 mm in diameter will connect the plant to the Trans-Caucasus gas pipeline. The new gas pipeline will be installed underground and will include all necessary auxiliary components, such as valves, restraints, supports, etc. to assure satisfactory operation. A metering station will be located on the plant site. The gas line will be constructed by Gazprom. A second source of natural gas will be available from underground storage caverns.

2.2.6 Transmission System Interconnection and Upgrades

A detailed study, included in Appendix I, was carried out of the region's existing transmission system to determine the upgrades that will be required to bring 900 MW of new capacity on line as proposed at the subject site. These studies included detailed load flow and fault analysis, dynamic studies and system stability studies.

These studies assume that the first stage of the interregional tie between the Center region of the Russian Integrated System and the North Caucasus comprising three 500 kV lines from Balakovskaya Nuclear Plant to Rostovskaya Nuclear Plant will become available prior to commissioning of the plant.

The load flow studies indicated that to deliver power to the regional consumers at 220 kV, three new substations will need to be constructed: in Kurgannaya, Cheremushki, and Zilposelok.

Figure 2.2-4 depicts a block diagram showing the existing lines, the re-routings and the additional lines that will be required . These additions and changes include:

- Reroute the existing 500 kV, 310 km line between Tzentralinaya and Zelenchukskaya via the 500 kV switchyard at the Krasnodar GRES Plant

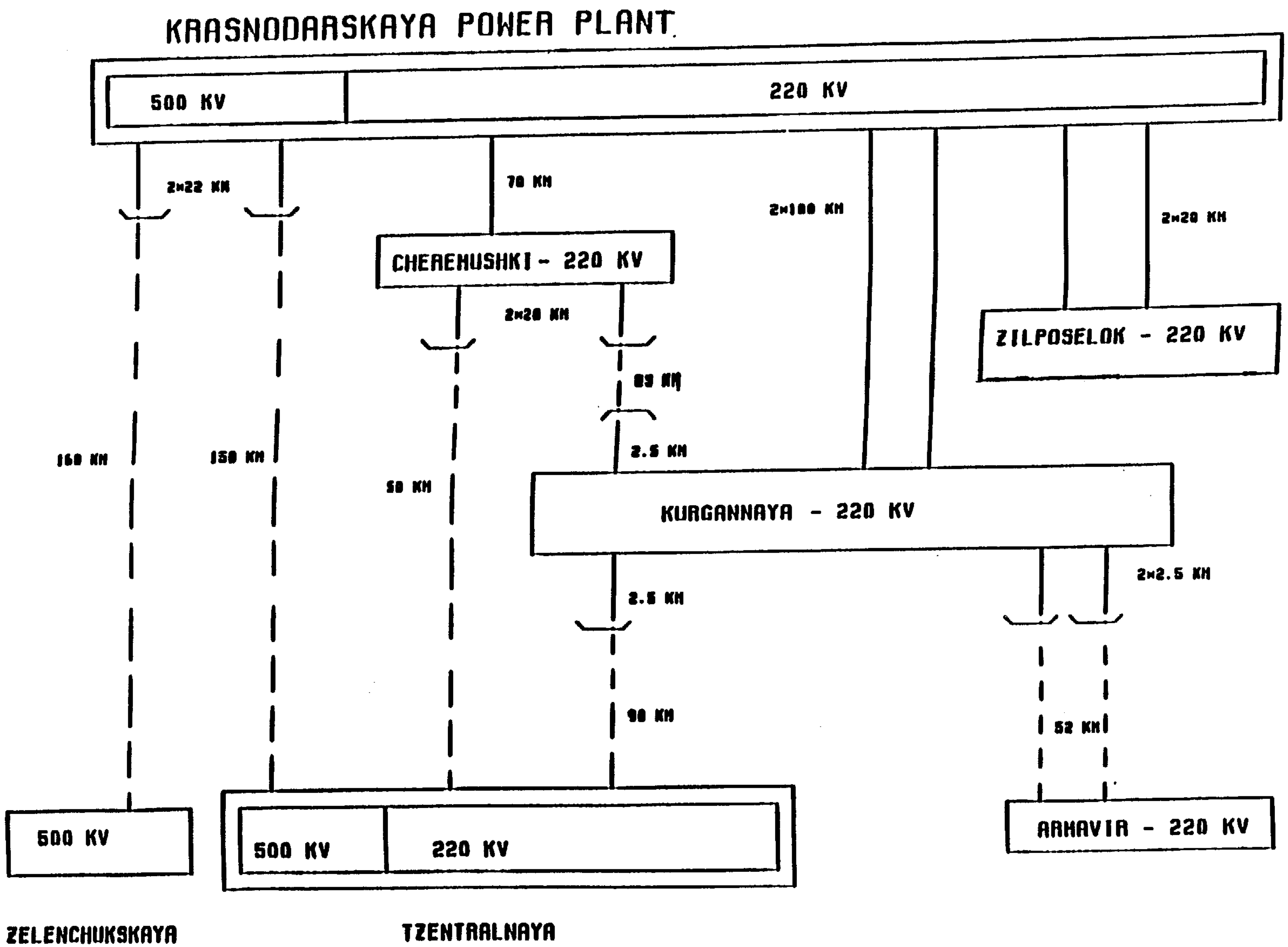
- Add a new single-circuit 220 kV line from Krasnodar GRES Plant to Cheremoshki substation:
- Add a new double-circuit 220 kV line from Kurgannaya to Zilposelok via Krasnodar GRES Plant:
- Reroute one circuit of the existing double-circuit 220 kV 185 km line between Tzentralnaya and Armavir via Cheremushki:
- Reroute the circuits of the above line via Kurgannaya:

2.2.7 The Switchyards

Figure 2.2-5 shows a plant switchyard one line. The Krasnodar GRES plant will have two switchyards: 500 kV and 220 kV.

The two switchyards will be interconnected by three single phase 167 MVA autotransformers. One spare transformer will be provided. A 180 MVA, 500 kV three phase shunt reactor will be provided to compensate for the reactive power in the 500 kV line.

The switchyard will be designed to be able to accommodate connections to the three new substations and to the existing 500 kV and 220 kV substations as shown on Figure 2.2-4.



KRASNODAR TRANSMISSION REINFORCEMENT

Figure 2.2-4

DOTTED LINE: EXISTING TRANSMISSIONS

SOLID LINE: TRANSMISSIONS DUE TO PROJECT

KRASNODAR 220 KV AND 500 KV TRANSMISSION REINFORCEMENT

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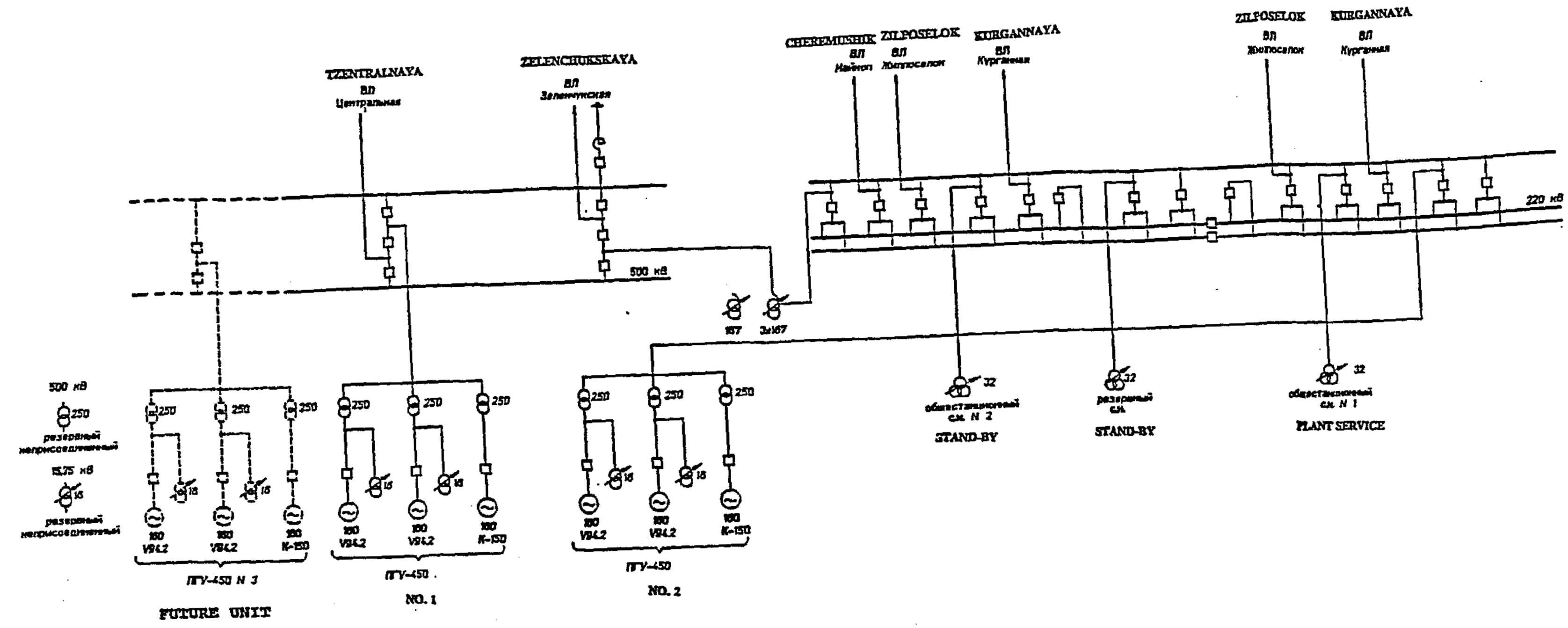

Figure 2.2-5
MAIN STATION ONE LINE

128-30-117			
Краснодарская ГРЭС			
Электротехническая часть 3хПГУ-450	Стадия: ТЭО	Лист	Листов: 1
Схема электрическая общая главная	АООТ ИНСТИТУТ РОСТОВТЕПЛОЭЛЕКТРОПРОЕКТ		

Должность	Фамилия	Подпись	Дата
Гл.инж.пр.	Тригер		10.94
Гл.спец.	Нагрямовский		10.94
Нач.отд.	Коротаев		10.94
Инж.	Бондарь		10.94

2.2.8 Relay Protection, Dispatch and Emergency Control

Relay Protection for Krasnodar GRES Transmission

The reliability of Krasnodar GRES could be enhanced by implementing modern transmission system protection schemes and devices. However, the modernization of the relay protection just for the Krasnodar transmission without widespread modernization of the transmission protection in the North Caucasus Power System will cause relay protection coordination problems. Therefore, the relay protection for the transmission facilities associated with the Krasnodar GRES will be implemented consistent with the standard protection practices currently being used by the Unified Power System in Russia. The single phase reclosure practices normally used in Russia for transmission lines of over 330 kV voltage will also be used on the two 500 kV lines emanating from the Krasnodar station to enhance the transient stability performance of the proposed KrasnodarGRES. Additional channels of teleinformation, including the status of circuit breakers, voltage and loading of new lines, will be provided to the North Caucasus Dispatch Center in Pyatigorsk. It is recommended that the new elements related to changes in regional transmissions and substations be added into the basic operational digital model of the Regional Power Supply.

Dispatch

The dispatch scheme and the associated devices for the Krasnodar GRES will be coordinated with existing telemetry system in the North Caucasus region. The dispatch of the Krasnodar generation is expected to follow the current practices of local and/or central dispatch methods being used in the North Caucasus Power System. A new modern telemetry system will be installed at the Krasnodar GRES. Upgrading the existing master computer system at the North Caucasus dispatch center is recommended for technical compatibility.

Emergency Control

The transmission reinforcement proposed for this project is adequate to support full output from the Krasnodar GRESunder most credible single contingency conditions. Therefore, no additional emergency control actions for this project are considered necessary. In 1997-1998, the new Adaptive Centralized Emergency Control (Remedial Action) System is expected to be put into operation in the North Caucasus Power System. Currently the existing system is able to operate without the emergency control only because of the dramatic reduction in demand in the neighboring Caucasian countries supplied through the North Caucasus Power System. This Remedial Action System will take into account the new status of the Power System after the Krasnodar GRES Plant will have been commissioned.

2.3 Performance Considerations

2.3.1 Plant Performance

Significant technology advances for combustion turbine combined cycle plants have occurred in terms of improved operating efficiency and lower emissions. For the Krasnodar GRES plant only combustion turbines in the 150 MW range with proven operating experience were considered. International suppliers continue to introduce new machines which use higher firing temperatures and advanced metallurgy to produce higher output and improved efficiency. However these newer machines do not have a proven track record.

The Krasnodar GRES plant is estimated to have a combined cycle efficiency of about 50% at full load. Figure 2.3-1a provides a heat balance diagram for one combined cycle module and identifies a total net generation of 466.7 MW and a net plant heat rate of 1683 kcal /kWh (6679Btu/kWh) based on ISO atmospheric conditions and the lower heating value of the fuel. The heat rate was estimated with the assumption that the plant will be operated as a base load plant with no district heating. Consideration was made for the impact of using an air cooled condenser. The plant will have a provision for a small amount of district heating load to meet the housing needs of the plant operating staff as a backup to the heating boilers that will be installed for district heating. Heat balance Figure 2.3-1b shows that with 10 gigacal/hr of district heating load from each unit, net generation from the same cycle conditions reduces to 464.8 MW

To illustrate the effects of full district heating load (50 gigacal/hr/unit) during a typical peak winter heating period (-15°C) heat balances Figure 2.3-2a and 2.3-2b (with and without district heating, respectively) are presented. These balances indicate a reduction in total net generation of 10.1 MW from each unit due to the district heating load.

Modern combined cycle plants can be expected to have an availability of about 90 percent. The reliability of the plant will be enhanced by requiring redundant systems and components in the detailed design. These requirements will be reflected in the procurement documents.

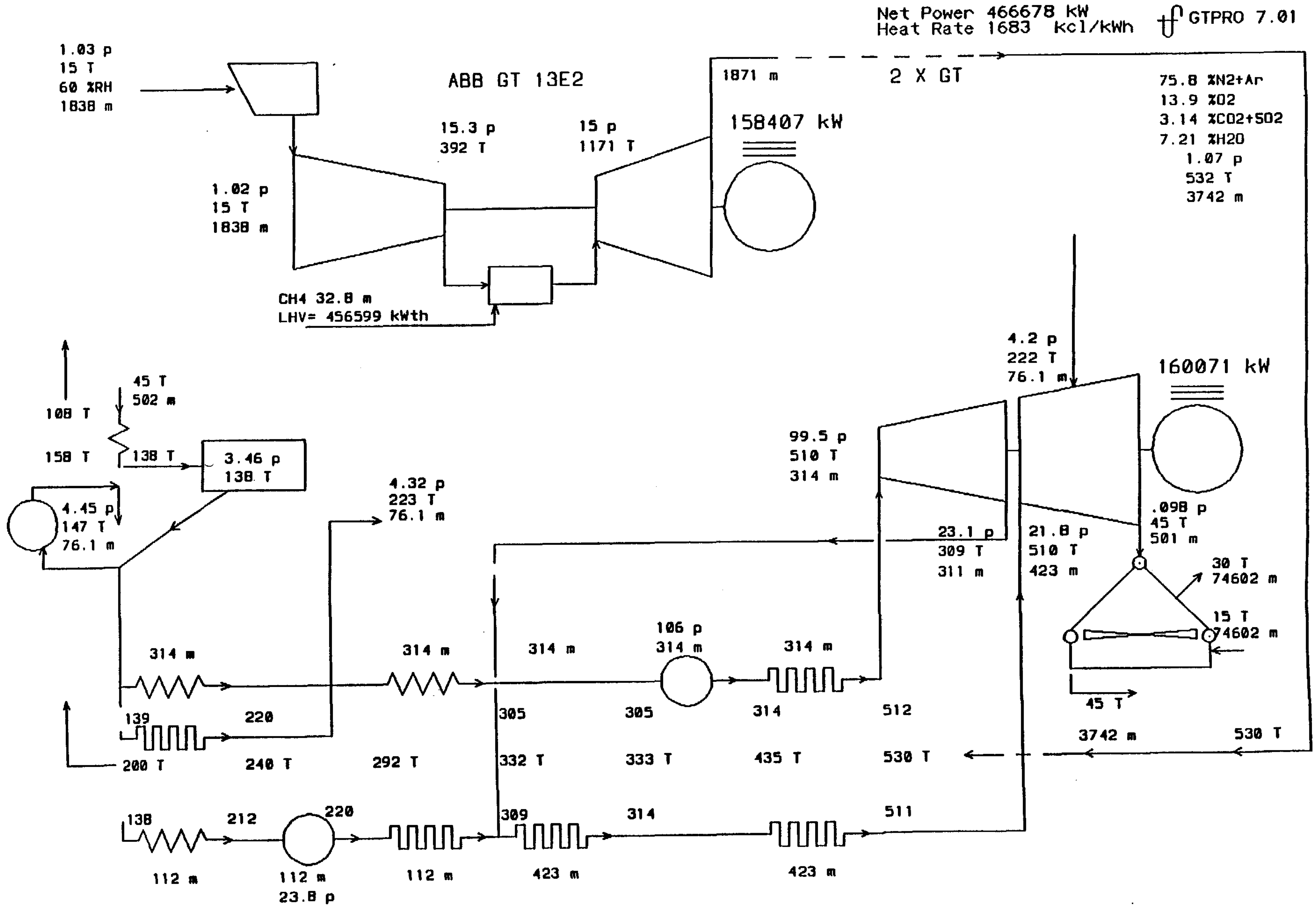

Figure 2.3-1a
Heat Balance : ISO Conditions, No District Heating

p = ata
T = °C
m = t/h

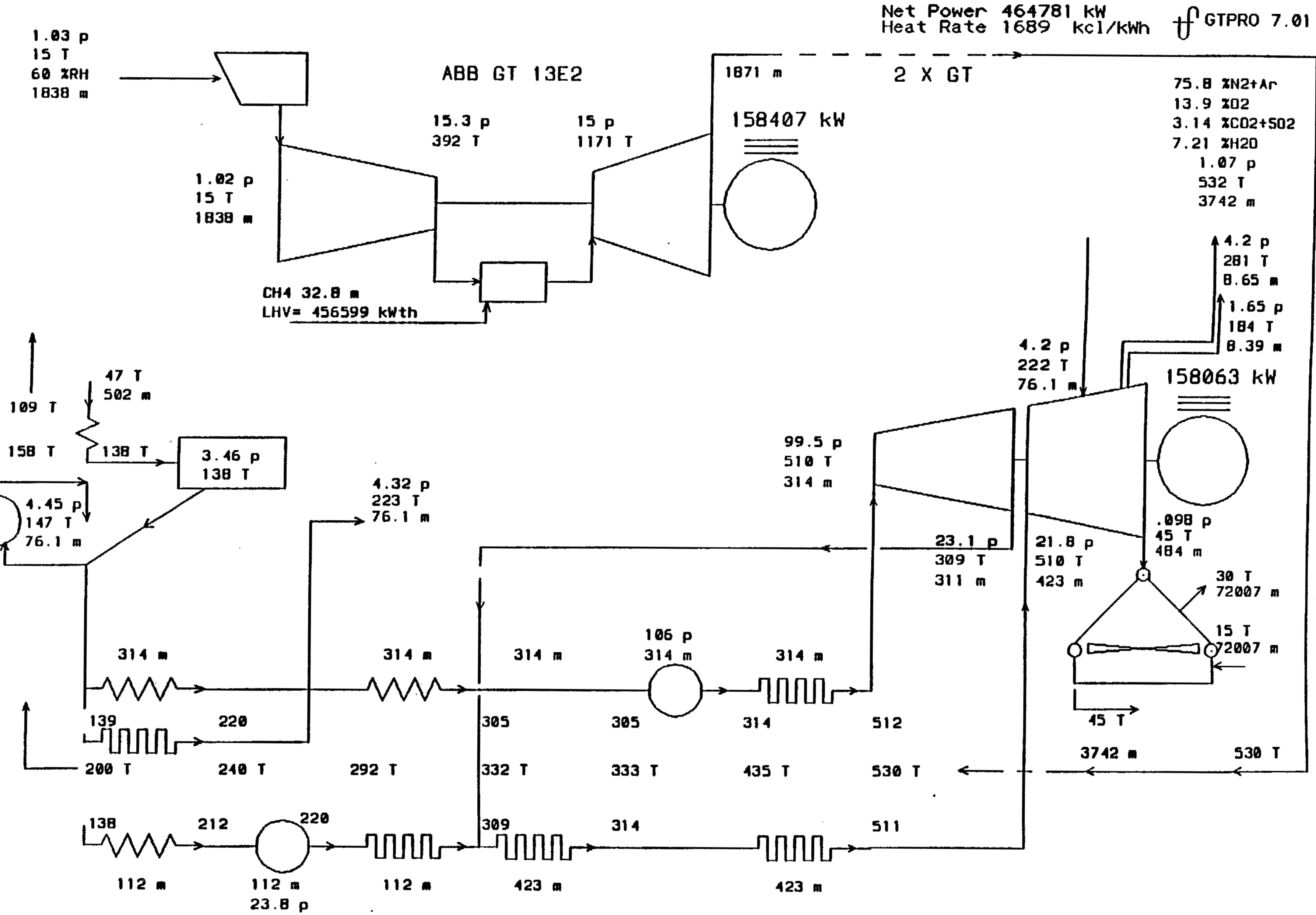

Figure 2.3-1b
Heat Balance : ISO Conditions, With District Heating

p = ata
T = °C
m = t/h

37

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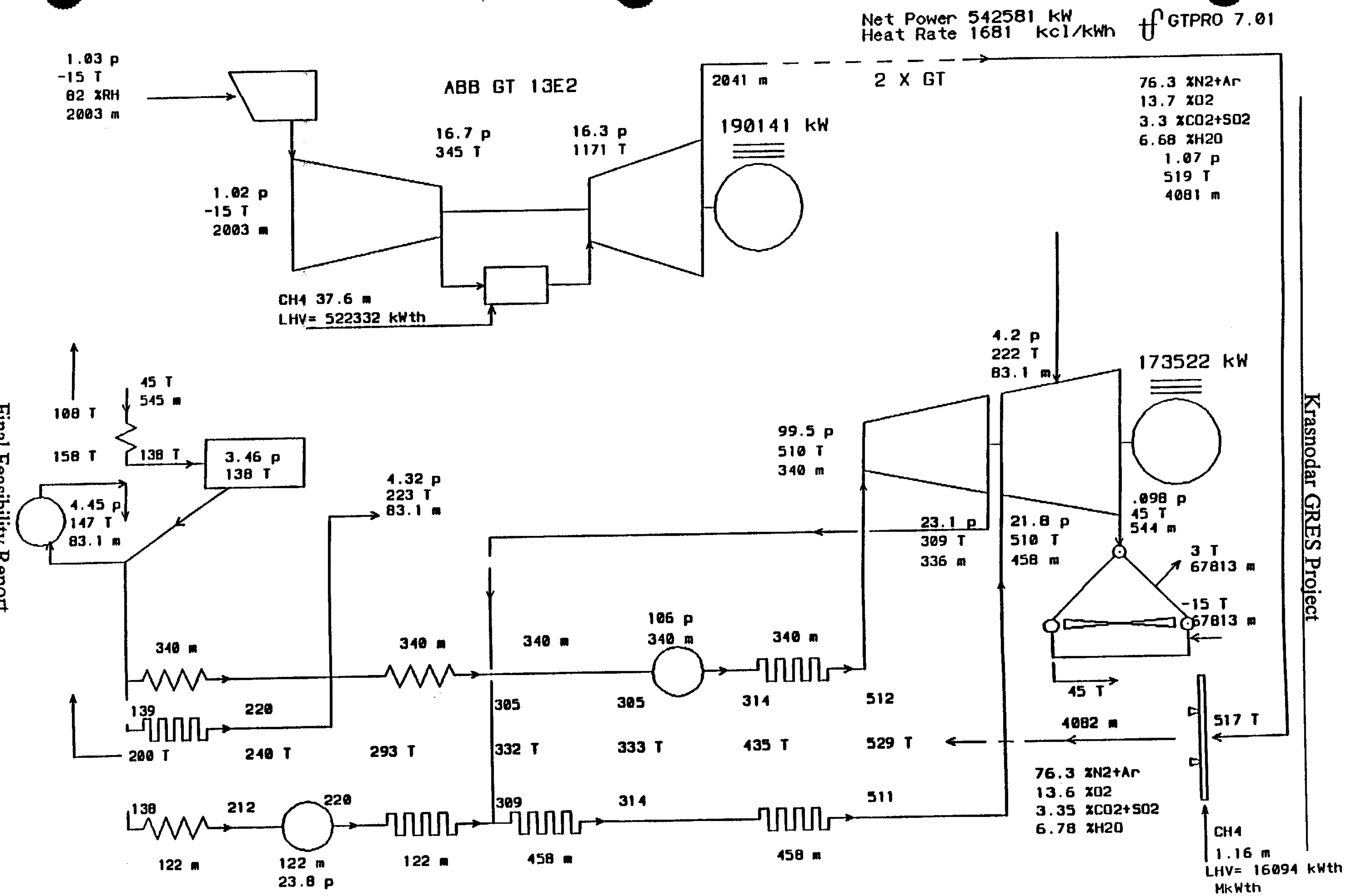

Figure 2.3-2a
Heat Balance : Winter Conditions, No District Heating

p = ata
T = °C
m = t/h

38

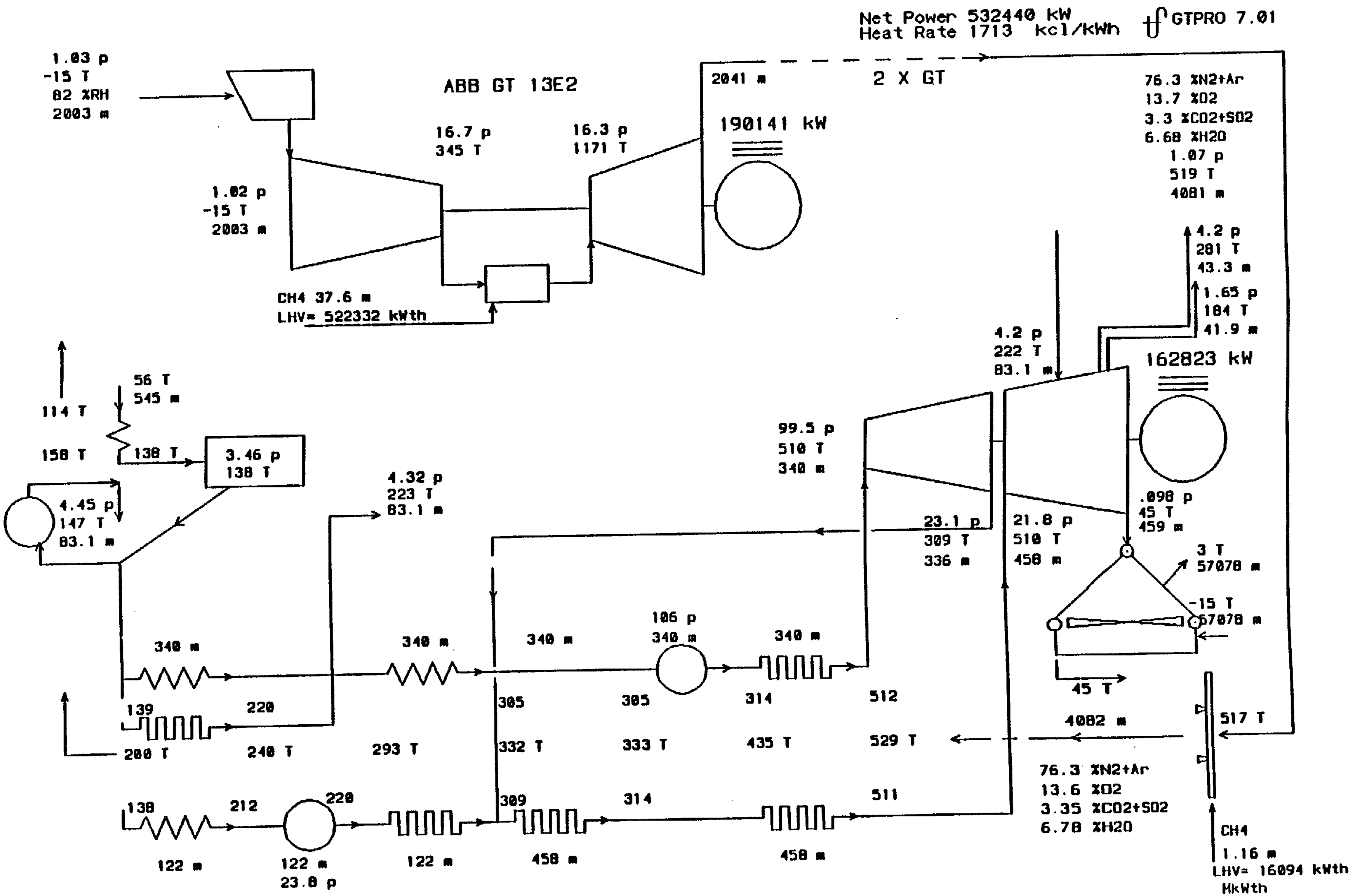

Figure 2.3-2b
Heat Balance : Winter Conditions, Maximum District Heating

p = ata
T = °C
m = t/h

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2.4 Project Capital Costs

2.4.1 Krasnodar GRES Power Plant

The capital cost for procurement and construction of the Krasnodar 900 MW combined cycle project is estimated to be US $478 million dollars (approximately $531 per kW) as shown in Table 2.4-1. A more detailed breakdown of the capital cost estimate is provided in Appendix H.

Representatives of the Project Ownership Group have commented that the Civil Works cost shown on Table 2.4-1 is too low. A modified capital cost is presented in Table 2.4-1A which increases the Civil Works cost to $39.5 million with a corresponding reduction in Indirect Costs.

Additional costs of $37.3 million (in 1995 US dollars) are estimated to be incurred by the Project Ownership Group (Table 2.4-2). For comparison purposes, the estimated cost of a similar plant constructed in the United States is shown in Table 2.4-3.

The assumptions and methodology used in estimating the cost of the power plant are described herein:

<u>Owner's Costs:</u>

Owner's costs shown in Table 2.4.-2 include pre-development costs including land, development expenses such as legal and environmental consultants, lender related expenses, working capital and pre-operational construction costs such as insurance. No separate lender's fees have been assumed. Foreign operation and maintenance training costs are included in the contractors' costs.

The pre-operational start up costs are for salaries, fringe benefits and related expenses of operating and maintenance (O&M) personnel during the period prior to commercial operation. It is assumed that an O&M staff will be built up slowly over a period of time starting from December 1, 1997 and that the staffing will be completed by one year prior to commissioning of the second combined cycle unit. The Owner's costs during start up include the following:

Staff salaries and fringe benefits
Staff temporary living expenses
Consumables and contracted Services
Capital items: computers, vehicles etc.
Miscellaneous costs

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TABLE 2.4-1

CAPITAL COSTS
900 MW KRASNODAR GRES PROJECT

DESCRIPTION	CAPITAL COSTS								
	NON-RUSSIAN (1995 US $ X 1000)			RUSSIAN (1995 US $ X 1000)					TOTAL
	EQUIPMENT	INDIRECT	SUBTOTAL	EQUIPMENT	MATERIALS	LABOR	INDIRECT	SUBTOTAL	(US $ X 1000)
CIVIL WORKS					9,092	7,883		16,975	16,975
MAJOR EQUIPMENT:									
Combustion Turbine Generator	120,000		120,000			440		440	120,440
Steam Turbine Generator	27,000		27,000			165		165	27,165
HRSG	34,500		34,500			1,760		1,760	36,260
Distributed Control System	2,900		2,900						2,900
MECHANICAL PACKAGE	26,000		26,000	20,496	11,205	5,137		36,838	62,838
ELECTRICAL PACKAGE				14,980	7,545	4,718		27,243	27,243
SWITCHYARD	29,818		29,818	3,200	1,440	6,400		11,040	40,858
Subtotal - Direct Costs	**240,218**		**240,218**	**38,676**	**29,282**	**26,503**		**94,461**	**334,679**
INDIRECTS		53,850	53,850				29,010	29,010	82,860
Subtotal	**240,218**	**53,850**	**294,068**	**38,676**	**29,282**	**26,503**	**29,010**	**123,471**	**417,539**
CONTINGENCY (Note #1)	24,022	5,385	29,407	9,669	7,321	6,626	7,253	30,868	**60,275**
TOTAL	**264,240**	**59,235**	**323,475**	**48,345**	**36,603**	**33,129**	**36,263**	**154,339**	**477,814**
TOTAL COST PER KW	**294**	**66**	**359**	**54**	**41**	**37**	**40**	**171**	**531**

NOTE #1. A base contingency of 10% has been included for all Non-Russian costs and 25% for all Russian costs.

TABLE 2.4-1A

MODIFIED CAPITAL COSTS (1)
900 MW KRASNODAR GRES PROJECT

DESCRIPTION	CAPITAL COSTS								
	NON-RUSSIAN (1995 US $ X 1000)			RUSSIAN (1995 US $ X 1000)					TOTAL
	EQUIPMENT	INDIRECT	SUBTOTAL	EQUIPMENT	MATERIALS	LABOR	INDIRECT	SUBTOTAL	(US $ X 1000)
CIVIL WORKS					21,330	18,170		39,500	39,500
MAJOR EQUIPMENT:									
Combustion Turbine Generator	120,000		120,000			440		440	120,440
Steam Turbine Generator	27,000		27,000			165		165	27,165
HRSG	34,500		34,500			1,760		1,760	36,260
Distributed Control System	2,900		2,900						2,900
MECHANICAL PACKAGE	26,000		26,000	20,496	11,205	5,137		36,838	62,838
ELECTRICAL PACKAGE				14,980	7,545	4,718		27,243	27,243
SWITCHYARD	29,818		29,818	3,200	1,440	6,400		11,040	40,858
Subtotal - Direct Costs	**240,218**		**240,218**	**38,676**	**41,520**	**36,790**		**116,986**	**357,204**
INDIRECTS		35,239	35,239				25,096	25,096	60,335
Subtotal	**240,218**	**35,239**	**275,457**	**38,676**	**41,520**	**36,790**	**25,096**	**142,082**	**417,539**
CONTINGENCY (2)	24,022	3,524	27,546	7,735	8,544	9,198	7,252	32,729	60,275
TOTAL	**264,240**	**38,763**	**303,003**	**46,411**	**50,064**	**45,988**	**32,348**	**174,811**	**477,814**
TOTAL COST PER KW	**294**	**43**	**337**	**52**	**56**	**51**	**36**	**194**	**531**

NOTES:

1. This modified capital cost estimate reflects a higher cost for the Civil Works package, and revised indirect costs and contingencies. The total project cost is the same as Table 2.4-1.
2. A base contingency of 10% has been included for all Non-Russian costs. The contingency for the Russian costs was provided by the Russian Ownership Group.

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Table 2.4-2

Owners' Costs (Other than Contractor Costs)

All Costs are in current U.S. dollars.

		Foreign (000s)	Domestic (000s)
A	Lender Related Expenses	2,000	
B.	Lender's Fees (1)	0	
C.	Development Expenses		
	Legal Counsel	800	200
	Accountants	250	
	Customs Specialist		100
	Out of pockets		250
	Pre Development Costs		8,000
	Recovery of Pre-development Costs		(600)
	Personnel Costs During Development		200
	Environmental Consultant	200	
D.	Pre-op Construction and O & M Costs		
	O & M Training (2)		600
	Consultants/Project Manager/A-E	13,500	1,100
	Insurance	7,000	
	Project Company Cost during construction		1,500
F.	Working Capital		
	Initial fills prior to start up	———	2,200
	TOTAL	23,750	13,550

Notes
1. Lender Fees are reflected in interest rate.
2 O & M training costs included in the Contractor's costs

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TABLE 2.4-3

CAPITAL COSTS - U. S. COST BASIS
900 MW KRASNODAR GRES PROJECT

DESCRIPTION	CAPITAL COSTS ($1,000)				TOTAL
	EQUIPMENT	MATERIALS	LABOR	INDIRECT	(US $ X 1000)
CIVIL WORKS		20,900	47,900		68,800
MAJOR EQUIPMENT:					
Combustion Turbine Generator	120,000		1,600		121,600
Steam Turbine Generator	27,000		600		27,600
HRSG	34,500		1,600		36,100
Distributed Control System	2,900		80		2,980
MECHANICAL PACKAGE	56,200	8,100	11,800		76,100
ELECTRICAL PACKAGE	21,400	10,800	17,100		49,300
SWITCHYARD	36,200	2,100	25,600		63,900
Subtotal - Direct Costs	**298,200**	**41,900**	**106,280**		446,380
INDIRECTS				83,000	83,000
Subtotal	**298,200**	**41,900**	**106,280**	**83,000**	529,380
CONTINGENCY (Note #1)	29,820	4,190	10,628	8,300	52,938
TOTAL	328,020	46,090	116,908	91,300	582,318
TOTAL COST PER KW	364	51	130	101	647

NOTE # 1. A base contingency of 10% has been included for all costs.

Note: Fuel costs are not included in the estimate.

Equipment and Installation Contract Costs:

In estimating the costs of the equipment contracts it is assumed that the contractors will procure the combustion turbines and the distributed control system (DCS) from international sources. It is further assumed that the contractors will be able to source all other power plant equipment, material and labor from Russia sources. However, for estimating purposes, foreign costs for the heat recovery steam generators, steam turbines and air cooled condensers were used. This includes installation of all power island equipment, procurement and installation of all balance of plant mechanical and electrical equipment, site preparation and civil works including roads and rail spurs within the site boundary, construction, and start up testing up to full commercial operation.

It is noted that the Civil Works cost shown in Table 2.4-1 does not represent a construction cost or the value of the Civil Works bid package. The Civil Works scope includes all site improvements, earthwork, roads, buildings and foundations, but does not include installation of equipment which is included in the separate equipment packages. Also, the indirect costs shown in Table 2.4-1 include field staffing, construction equipment, temporary facilities and other items which will be included in the scope and cost of the Civil Works bid package.

A conceptual design of the plant was established to arrive at a detailed estimate. To describe the scope of the work, a preliminary list of major equipment was compiled from preliminary system flow diagrams and one line diagrams.

A modified site plan and plant general arrangement were developed taking into consideration the equipment of major international suppliers for the 900 MW plant. A conceptual heat balance representative of the major suppliers of combined cycle plants was developed for a 450 MW block and used as the basis for developing the flow diagrams. The material quantities were estimated from these preliminary drawings and sketches. It is assumed that backfill for the site will be available at no cost.

The estimate assumes an air cooled condenser. All construction material including specialty steel is assumed to be available from Russian sources. The cost of the 220 kV/500 kV switchyards within the site boundary is included in the estimate.

It should be noted that little information was available from Russian sources about current market prices. The information offered was at best sketchy but nevertheless valuable as it enabled the consultants to add their judgement to arrive at domestic prices for equipment, materials and labor. Labor productivity was assumed to be one-fourth of that in the United States.

Contingency represents an allowance for the level of accuracy of the estimate. The many unknowns in the sourcing and pricing of the equipment dictate a higher contingency allowance for the Russian sourced work. Spare parts for two years and operator training up to one year after initial commercial operation are included in the estimate. Taxes and import duties and interest during construction are not included in the estimate. Freight costs are included in the estimate.

Contractor's other indirect costs include field staffing, construction service and support, facilities and utilities, construction equipment, insurance, spare parts, security and engineering.

The estimate assumes a construction schedule of 42 months from the award of the first equipment contract, assumed to occur on December 1, 1996. It is planned that the plant will be brought on line in stages as follows: 1) 300 MW simple cycle in 24 months 2) 300 MW simple cycle in the next 6 months 3) 150 MW combined cycle addition to the first 300 MW simple cycle in the next 6 months, followed by 4) a similar extension for the second unit in 6 additional months. For a detailed project schedule, refer to Section 2.6.1.

2.4.2 Cash Disbursement Schedule

The cash disbursement schedule is derived from the milestone schedule shown in Fig 2.6-1 and is a function of when major equipment items are delivered and the overall construction progress. Table 2.4-4 identifies estimated total cash disbursements for each procurement package and Owners costs. The values shown are rough estimates. A detailed disbursement schedule will be negotiated with each successful contractor for its package.

2.4.3 The Gas Line

The gas line costs for a 700 mm gas line adequate for a 1,350 MW capacity plant are estimated to be $38.05 million (in U.S. dollars, estimated by Burns and Roe). A more exact estimate in current rubles has been requested of Gazprom. These costs are based on Russian supply and include all material, construction, labor and associated right of way costs. It is also assumed that the gas line will be constructed to be available in time to allow testing of the first combustion turbines in about 18 months from December 1, 1996. Note that the cost of a metering station to be located at the plant site is included in the contract estimate.

TABLE 2.4-4
KRASNODAR GRES PROJECT
CASH FLOW SCHEDULE

ACCOUNT	VALUE	PRIOR	1996				1997				1998				1999				2000				Total
	($ million)	TO 1996	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
Bid Packages (1)																							
Comb. Turbin	170.0	0.0	0.0	0.0	0.0	17.0	5.0	10.0	10.0	10.0	20.0	16.0	16.0	16.0	15.0	15.0	15.0	5.0	0.0	0.0	0.0	0.0	170.0
HRSG	50.0	0.0	0.0	0.0	0.0	0.0	5.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	50.0
Steam Turbine	40.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	2.0	2.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	2.0	2.0	2.0	2.0	40.0
Switchyard	47.0	0.0	0.0	0.0	0.0	4.0	2.0	2.0	4.0	4.0	4.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	0.0	0.0	47.0
Electrical	40.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	2.0	2.0	3.0	4.0	4.0	4.0	3.0	3.0	2.0	2.0	2.0	2.0	2.0	1.0	40.0
Mechanical	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	6.0	6.0	8.0	8.0	8.0	8.0	7.0	7.0	7.0	7.0	6.0	6.0	6.0	100.0
Civil Works	28.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	1.0	1.0	1.0	28.0
DCS	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	3.0
Sub Total	478.0	0.0	0.0	0.0	0.0	21.0	12.0	26.3	33.2	29.2	41.2	39.2	39.2	39.2	37.2	36.2	35.2	25.2	19.2	17.2	14.2	13.1	478.0
Owner's Costs	37.3	8.0	0.3	1.0	3.5	1.8	2.7	2.9	3.0	3.0	1.1	1.9	0.9	0.9	0.9	1.0	0.7	0.8	0.8	0.8	0.7	0.6	37.3
Total Costs	515.3	8.0	0.3	1.0	3.5	22.8	14.7	29.2	36.2	32.2	42.3	41.1	40.1	40.1	38.1	37.2	35.9	26.0	20.0	18.0	14.9	13.7	515.3
PERCENT		1.6	0.1	0.2	0.7	4.4	2.8	5.7	7.0	6.2	8.2	8.0	7.8	7.8	7.4	7.2	7.0	5.1	3.9	3.5	2.9	2.7	100.00

Note: 1. Value of each package includes an allocation of indirect costs and contingency.

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2.4.4 Transmission Upgrades

To deliver power to the regional consumers at 220 kV, three new substaitons will need to be constructed: in Kurgannaya, Cheremushki, and Zilposelok.

These substations together will contain:

- 220 kV circuit breakers - eighteen, three-phase units
- 110 kV circuit breakers - five, three-phaase unit
- step-down 125 MVA 220/110 kV transformer - five, three-phase units

It has been estimated that to accommodate the above mentioned new substations, 44 km of 500 kV and 360 km of 220 kV transmission lines will either be rerouted or added.

The cost of adding and rerouting the transmission lines is estimated to be $45 million, including $3 million in foreign costs. The cost of the three substations is estimated to be $27.3 million, including $19.1 million in foreign costs.

The cost of the 500 kV and 220 kV switchyards is included in the plant costs.

A separate estimate was provided by RAO/EES Rossii and is shown in Table 2.4-5. It is noted that the cost estimate in Table 2.4-5 is significantly lower than the $72.3 million identified above as estimated by the U.S. consultants. Scope differences can explain a portion of this difference. The consultant estimate includes 360 km of 220 kV line whereas the RAO estimate includes only 130 km. Using RAO's estimate for $/km (from item #2 on Table 2.4-5) the additional transmission line would cost $14.0 million. Also, the RAO estimate includes two substations while the U.S. estimate includes a third substation at Zilposelok (approx. cost using RAO figures is $4.5 million). Also, the U.S. estimate includes $19.1 million in foreign costs which may included as domestic content in the RAO estimate. The RAO estimate as adjusted should be considered the more accurate.

2.5 Operation and Maintenance Costs

The operation phase of the project contemplates that Kuban GRES will be the operator of the plant. A detailed breakdown of the operating and maintenance costs developed is shown in Table 2.5-1.

O&M costs include operating labor, total maintenance and overhead components.

The project O&M costs are based on the following assumptions.

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Table 2.4-5

900 MW Krasnodar GRES Project,
Transmission Upgrades,
Lengths, Capacities, and Costs
(Provided by RAO EES Rossii)

#	Transmission Facility	Transmission Length/ Substation Capacity	Cost, $ Million
1	Kuban GRES -- Inguri-Tsentralnaya 500 KV Transmission Line	2 x 22 km	9
2	220 KV Transmission Line Kuban GRES - Kurgannaya	2 x 60 km	7.3
3	220 KV Substation, Mostovskoy (Settlement)	2 x 125 MVA	4.5
4	229 KV Substation, Kurgannaya	2 x 125 MVA 2 x 5 km	5.1
	TOTAL		25.9

- The costs for spare parts for international supplied equipment are estimated in US dollars. All other costs estimates are in rubles.
- The salaries and benefits costs have been estimated from information received from ROTEP and Kubanenergo.
- The permanent staff will be responsible for operation and routine maintenance.
- Major overhauls and periodic maintenance will be subcontracted.

The operating costs for a generating unit are generally allocated as fixed and variable costs.

2.5.1 Fixed Costs

The fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced and are expressed as $/kW-year.

The fixed operating costs are composed of personnel salaries and fringe benefits, operating labor and supervision, fixed maintenance costs and overhead charges such as property taxes and insurance.

Fixed costs are estimated to be $6.18 per kW.

2.5.2 Variable Costs

Consumables are the principal components of the variable costs. These include water, chemicals and other materials that are consumed in proportion to energy output. Annual maintenance, periodic overhauls, subcontracts, and spares were split between the fixed and variable costs.

Variable costs are estimated at $ 0.71 per MWh.

2.6 Project Implementation

During the course of the development phase, the Owners Group will evolve into the project company, Kuban GRES. This company will manage the implementation of the project from issuing the invitation to bids through plant operation. The project implementation is described in the following phases:

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TABLE 2.5-1

ANNUAL OPERATING AND MAINTENANCE COST ESTIMATE
(All costs in 1000'S of U.S. dollars)

	Total	Domestic Material	Domestic Labor	Domestic Out of Pockets	Foreign Material	Foreign Labor	Foreign Out of Pockets
Fixed Costs							
Salaries	875	---	875	---	---	---	---
Indirects (1)	400	80	25	295	---	---	---
Maintenance (annualized)(2)	4,200	275	35	115	3,550	---	225
Total Fixed Cost	5,475	355	935	410	3,550	0	225

Assuming a net plant output of 886 MW; fixed cost per kW of installed capacity = $6.18

	Total	Domestic Material	Domestic Labor	Domestic Out of Pockets	Foreign Material	Foreign Labor	Foreign Out of Pockets
Variable Costs							
Consumables	400	400	---	---	---	---	---
Indirects (1)	60	60	---	---	---	---	---
Maintenance (annualized)(2)	4,200	275	35	115	3,550	---	225
Total Variable Cost	4,660	735	35	115	3,550	0	225

Assuming an 85% plant capacity factor; variable cost per MWh = $0.71

Notes:
(1) Includes $250,000 for insurance as an out of pocket expense. Property taxes not included.
(2) The annualized maintenance costs are allocated equally between fixed and variable costs.

Project Development:

This phase of the project includes the development work by the Owner and its consultants, e.g., land acquisition, feasibility studies, environmental impact statements and regulatory permits. Sources of debt and equity financing and project contracts are also developed. This work is in progress.

Tender Documents and Bid Packages:

This phase of the project consists of preparing tender documents for international bidding, evaluation of bids and negotiations leading to contract award. This work is currently underway. A draft commercial section of each package has been developed in accordance with The World Bank guidelines. The international competitive bid process is discussed in Chapter 5. Burns and Roe and ROTEP have prepared Draft technical specifications for the equipment in the power block and for the balance of plant equipment.

Construction:

The activities during the construction phase, begin with the award of the equipment and installation contract and continue up to the commissioning of the Unit 2 combined cycle.

During this phase of the project implementation, the project company, Kuban GRES, will set up offices and facilities at the site in preparation for takeover of the power plant equipment and systems, as they are tested and found acceptable. Early participation of the utility staff is essential.

2.6.1 Project Milestone Schedule

Figure 2.6-1 provides a schedule of all procurement, engineering and construction activities for the Krasnodar GRES project. Milestones for availability of the gas and transmission lines are also shown. The schedule of activities is such that all systems are in place and fully operational for the mode of operation at the time a unit is commissioned in simple cycle or combined cycle mode.

Key milestone dates are as follows:

Combustion Turbine Package	
Release of Invitation to Bid	February 1, 1996
Receipt of bids	May 15, 1996
Award of Combustion Turbine Contract	December 1, 1996
Delivery of First Combustion Turbine	March 1, 1998
Natural Gas Available	June 1, 1998

SV

500 kV Transmission System Operational	August 1, 1998
Commercial Operation of First Simple Cycle Units (300 MW)	December 1, 1998
220 kV Transmission System Operational	February 1, 1999
Commercial Operation of Second Simple Cycle Units (300 MW)	June 1, 1999
Commercial Operation of First Combined Cycle Unit (150 MW)	December 1, 1999
Commercial Operation of Second Simple Cycle Units (150 MW)	June 1, 2000

2.6.2 Bid Packaging

The tender documents will be prepared on the basis of the 900 MW combined cycle project selected. Consideration was given to use of a single bid package that will ensure a single point of responsibility. This turnkey approach minimizes the complexities associated with administering many separate contracts, due to interface issues among contractors. In addition it maximizes control of schedule and performance guarantees required of the contractor(s) and the impact on guarantees resulting from the interrelated performance of different components of the plant.

However, as requested by the Owners' Group, the contracts were broken into the following seven packages:

- Combustion turbine generators and fuel supply system
- Heat recovery steam generators, steam turbine generators and auxiliary systems
- Distributed control system
- Major electrical equipment
- Switchyard
- Plant auxiliary systems
- Civil works

The international competitive bidding process is described in Chapter 5.

Particular emphasis is placed in the bid documents to encourage the domestic content of the bids to be as large as possible. This is done in two ways: 1) following the World Bank guidelines for procurement of the international bid portion of the project in which a credit is given for domestic supply and 2) requiring the supply of domestic equipment for that part of the project which is not World Bank financed.

It is assumed that the portions of the project that are not financed by the World Bank and that will not have an impact on plant performance, (e.g., the off site facilities) will be procured and constructed separately by Owner.

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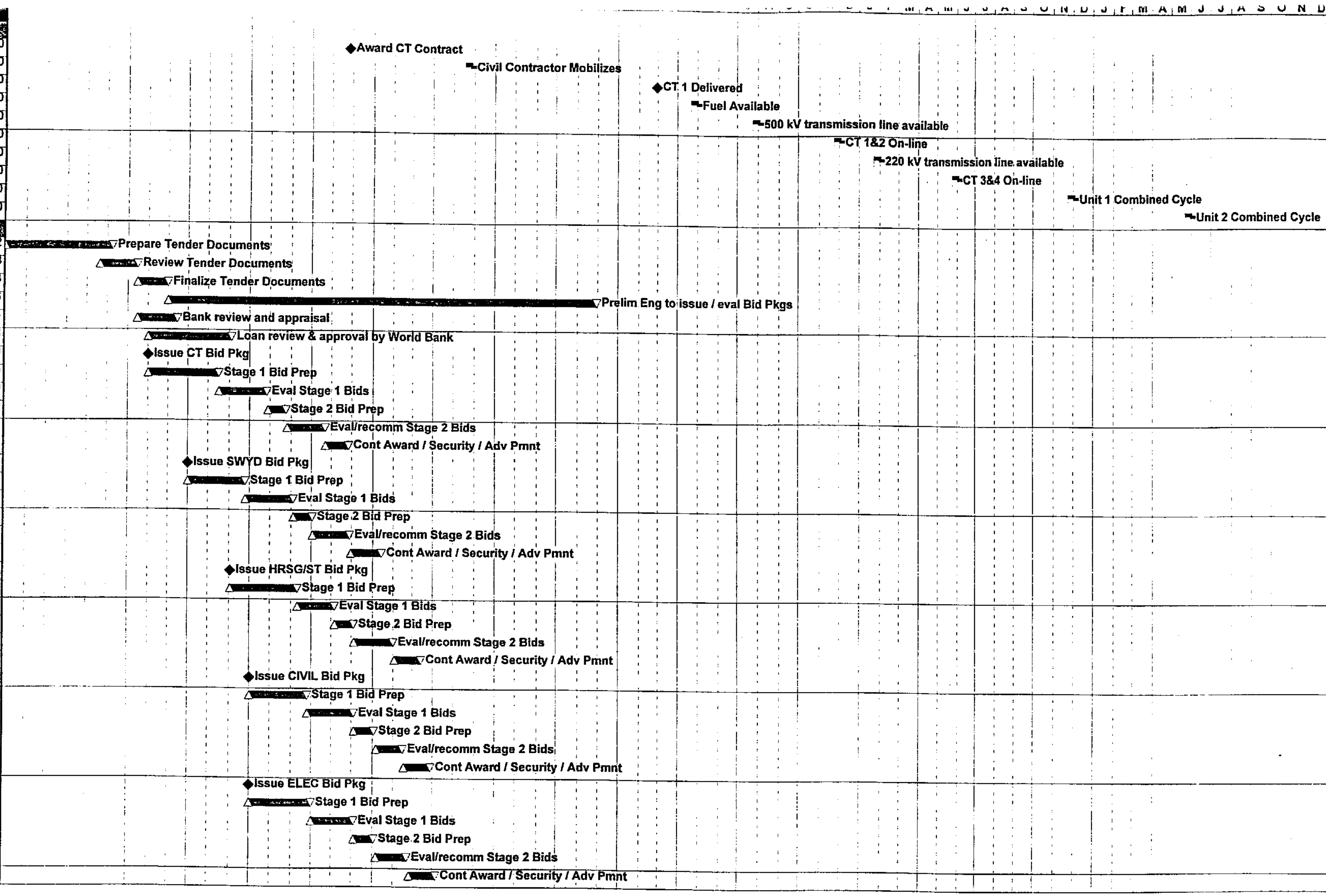
All Phases

ID	Activity	Duration
PROJECT MILESTONES		
1000	Award CT Contract	0
1010	Civil Contractor Mobilizes	0
1020	CT 1 Delivered	0
1030	Fuel Available	0
1035	500 kV transmission line	0
1040	CT 1&2 On-line	0
1045	220 kV transmission line	0
1050	CT 3&4 On-line	0
1060	Unit 1 Combined Cycle	0
1070	Unit 2 Combined Cycle	0
TENDER DOCUMENT		
1500	Prepare Tender Documents	112
1510	Review Tender Documents	38
1520	Finalize Tender Documents	33
1530	Prelim Eng to issue / eval Bid	446
1560	Bank review and appraisal	44
1570	Loan review & approval by	88
1600	Issue CT Bid Pkg	0
1602	Stage 1 Bid Prep	75
1604	Eval Stage 1 Bids	50
1606	Stage 2 Bid Prep	20
1608	Eval/recomm Stage 2 Bids	40
1610	Cont Award / Security / Adv	26
1612	Issue SWYD Bid Pkg	0
1614	Stage 1 Bid Prep	60
1616	Eval Stage 1 Bids	50
1618	Stage 2 Bid Prep	20
1620	Eval/recomm Stage 2 Bids	40
1622	Cont Award / Security / Adv	30
1624	Issue HRSG/ST Bid Pkg	0
1626	Stage 1 Bid Prep	70
1628	Eval Stage 1 Bids	40
1630	Stage 2 Bid Prep	20
1632	Eval/recomm Stage 2 Bids	40
1634	Cont Award / Security / Adv	30
1636	Issue CIVIL Bid Pkg	0
1638	Stage 1 Bid Prep	60
1640	Eval Stage 1 Bids	50
1642	Stage 2 Bid Prep	20
1644	Eval/recomm Stage 2 Bids	30
1646	Cont Award / Security / Adv	30
1648	Issue ELEC Bid Pkg	0
1650	Stage 1 Bid Prep	65
1652	Eval Stage 1 Bids	45
1654	Stage 2 Bid Prep	20
1656	Eval/recomm Stage 2 Bids	35
1658	Cont Award / Security / Adv	30



Project Start	01JUL95
Project Finish	28JUN00
Data Date	01JUL95
Plot Date	23FEB96

Early Bar
Progress Bar
Critical Activity

KRAS

Sheet 1 of 3

Figure 2.6-1
KRASNODAR GRES PROJECT
MILESTONE SCHEDULE

Date	Revision	Checked	Approv

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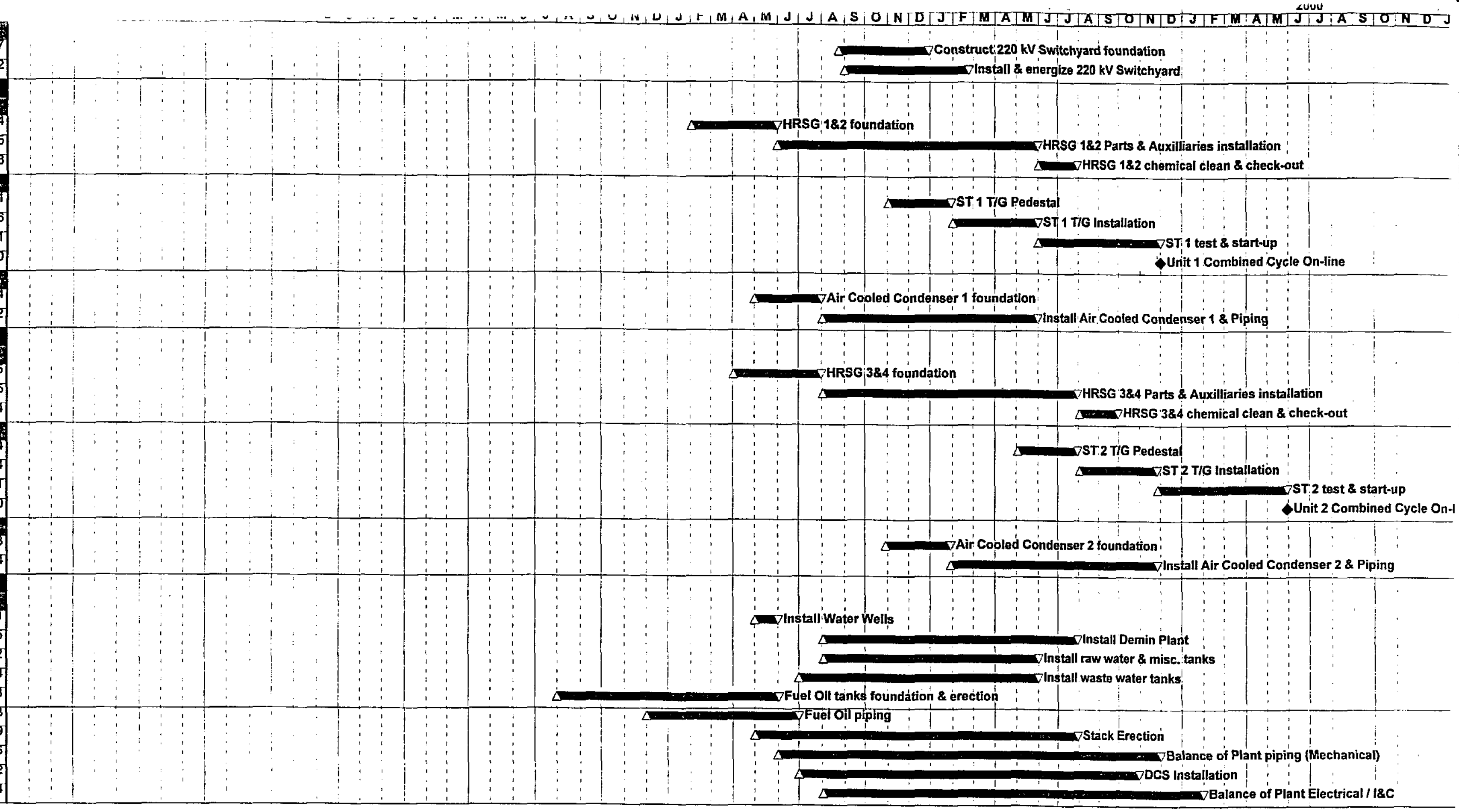
ID	Activity	Duration
SWITCHYARD		
6560	Construct 220 kV Switchyard	87
6570	Install & energize 220 kV	122
Combined Cycle One		
HRSG		
4500	HRSG 1&2 foundation	84
4525	HRSG 1&2 Parts & Auxilliaries	255
4540	HRSG 1&2 chemical clean &	43
STEAM TURBINE		
5000	ST 1 T/G Pedestal	61
5020	ST 1 T/G Installation	86
5040	ST 1 test & start-up	131
5045	Unit 1 Combined Cycle On-line	0
COOLING TOWER		
6000	Air Cooled Condenser 1	64
6020	Install Air Cooled Condenser 1	212
Combined Cycle Two		
HRSG		
4530	HRSG 3&4 foundation	85
4545	HRSG 3&4 Parts & Auxilliaries	255
4550	HRSG 3&4 chemical clean &	44
STEAM TURBINE		
5030	ST 2 T/G Pedestal	64
5035	ST 2 T/G Installation	84
5050	ST 2 test & start-up	131
5055	Unit 2 Combined Cycle On-line	0
COOLING TOWER		
6025	Air Cooled Condenser 2	63
6030	Install Air Cooled Condenser 2	214
Balance of Plant		
SITEWORK/UTIL		
3100	Install Water Wells	21
3120	Install Demin Plant	255
3130	Install raw water & misc. tanks	212
3140	Install waste water tanks	234
3150	Fuel Oil tanks foundation &	213
7020	Fuel Oil piping	148
7210	Stack Erection	319
8010	Balance of Plant piping	386
8030	DCS Installation	342
8090	Balance of Plant Electrical /	384



Project Start	01JUL95
Project Finish	28JUN00
Data Date	01JUL95
Plot Date	23FEB96

Early Bar
Progress Bar
Critical Activity

KRAS

Sheet 3 of 3

Figure 2.6-1

KRASNODAR GRES PROJECT

MILESTONE SCHEDULE

Date	Revision	Checked	Approved

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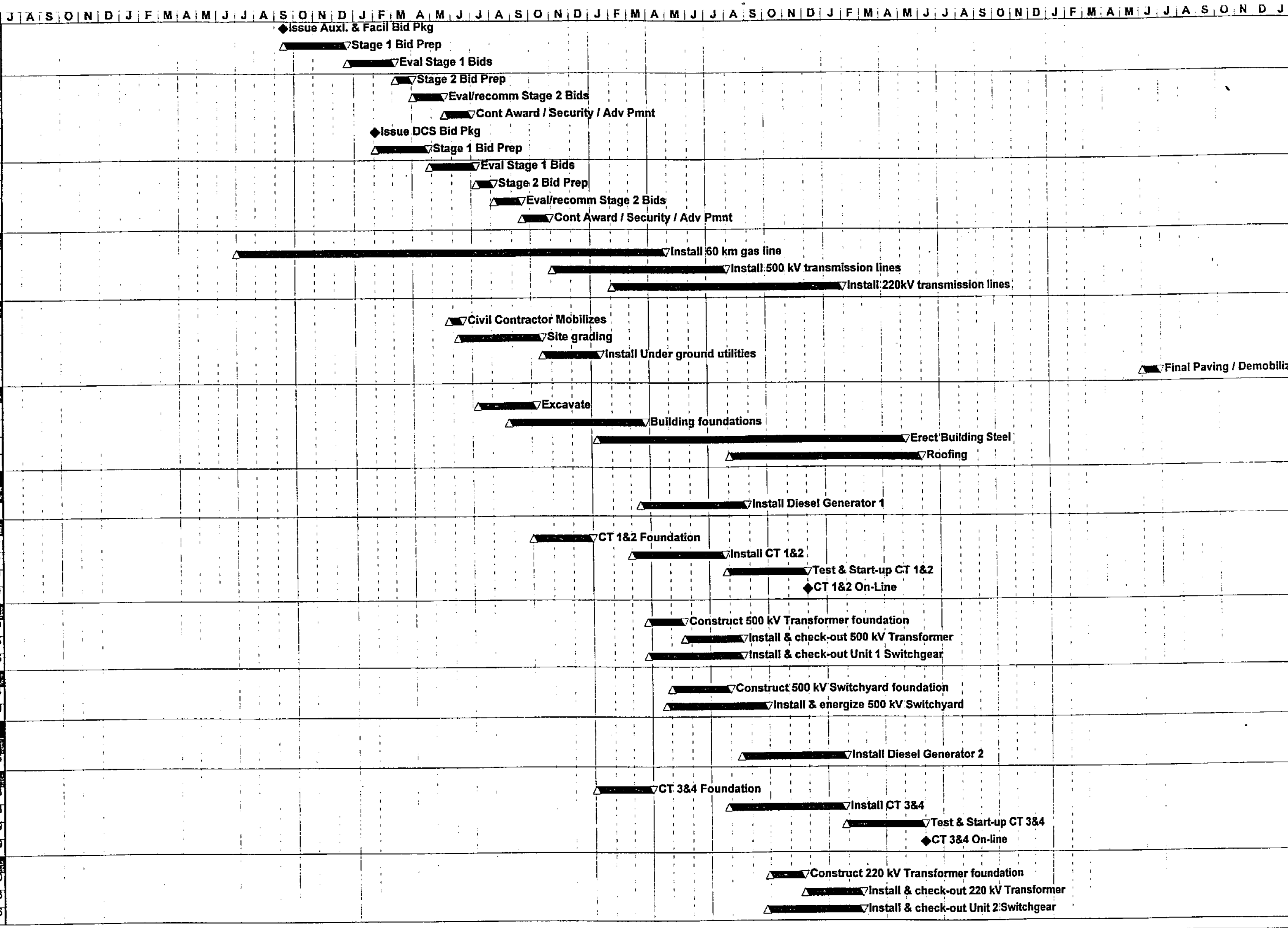
ID	Description	Dur
1660	Issue Auxl. & Facil Bid Pkg	0
1662	Stage 1 Bid Prep	70
1664	Eval Stage 1 Bids	50
1666	Stage 2 Bid Prep	20
1668	Eval/recomm Stage 2 Bids	35
1670	Cont Award / Security / Adv	30
1672	Issue DCS Bid Pkg	0
1674	Stage 1 Bid Prep	60
1676	Eval Stage 1 Bids	50
1678	Stage 2 Bid Prep	20
1680	Eval/recomm Stage 2 Bids	30
1682	Cont Award / Security / Adv	30
GAS & TRANSMISSION LINES		
1700	Install 60 km gas line	467
1710	Install 500 kV transmission	190
1720	Install 220kV transmission lines	254
SITEWORK / UTIL		
3000	Civil Contractor Mobilizes	16
3005	Site grading	91
3010	Install Under ground utilities	61
3020	Final Paving / Demobilize	20
MAJOR CIVIL/STRUCTURAL		
3500	Excavate	64
3510	Building foundations	147
3520	Erect Building Steel	341
3530	Roofing	212
Simple Cycle One		
SITEWORK / UTIL		
3050	Install Diesel Generator 1	118
COMBUSTION TURBINE		
4000	CT 1&2 Foundation	64
4010	Install CT 1&2	103
4020	Test & Start-up CT 1&2	89
4030	CT 1&2 On-Line	0
MAIN TRANSFORMERS		
5500	Construct 500 kV Transformer	40
5520	Install & check-out 500 kV	65
5560	Install & check-out Unit 1	106
SWITCHYARD		
6500	Construct 500 kV Switchyard	64
6510	Install & energize 500 kV	110
Simple Cycle Two		
SITEWORK / UTIL		
3060	Install Diesel Generator 2	116
COMBUSTION TURBINE		
4070	CT 3&4 Foundation	63
4080	Install CT 3&4	128
4120	Test & Start-up CT 3&4	89
4130	CT 3&4 On-line	0
MAIN TRANSFORMERS		
5530	Construct 220 kV Transformer	40
5550	Install & check-out 220 kV	63
5570	Install & check-out Unit 2	106



Project Start	01JUL95
Project Finish	28JUN00
Data Date	01JUL95
Plot Date	23FEB96

Early Bar
Progress Bar
Critical Activity

KRAS

Sheet 2 of 3

Figure 2.6-1
KRASNODAR GRES PROJECT
MILESTONE SCHEDULE

Date	Revision	Checked	Approved

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2.6.3 Procurement Plan

The Kuban GRES project company will issue invitations for bids to the interested suppliers and consortia in accordance with the World Bank guidelines. In addition to incentives for maximizing the domestic content of the bids, other incentives and penalties will be specified in the bid documents to encourage bidders' commitment to schedule, performance and reliability. A two stage bidding process for each package will be followed. In the first stage of bidding the bidders will be asked to submit information about their eligibility and that of their joint venture partners, proposed subcontractors, and identify deviations and exceptions to the bid documents. Selection criteria will include: international reputation, specific experience of the bidder and proven technical performance of the equipment offered, willingness to perform to international standards and to provide suitable guarantees of performance and financial strength. Clarification meetings will then be held with the bidders.

In the second stage of bidding the bidders will be asked to submit the technical bids, the price schedules, a memorandum of clarification meetings, and other bid documents and forms as required under the World Bank procurement guidelines.

The two stage approach will maximize bids from truly interested and qualified participants.

Bid evaluations will be performed utilizing the guidelines in the bidding documents and the bid evaluation factors to ensure that all bidders are treated equally. It is recommended that Kuban GRES use an engineering consultant with international procurement experience to assist in this process. Kuban GRES, will enter into fixed price, lump sum , turnkey contracts with the successful bidders. Further information about the content of the bidding documents is provided in Chapter 5.

2.6.4 Project Management

The organization and governance of Kuban GRES is presented in Section 4.2.10 of this report and its Project Development Team, organized to execute the Krasnodar GRES Project, is described in Section 4.2.11.

As part of that team the Construction Manager is responsible for all aspects directly related to the building of the plant: contract administration, engineering, construction, schedules, costs and quality control. He will be responsible for controlling the construction budget. All contractors will be responsible for their work to the Construction Manager. He will be the sole point of contact for the contractors and will be responsible for resolving all contractor issues relating to schedule, cost and change orders, and will make recommendations concerning these items to the Project Development Team Leader.

The Construction Manager will be responsible for review of design, engineering, procurement specifications submitted by the contractor for Owner's review and oversee

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construction to ensure that engineering, construction, and procurement are in compliance with the contract documents, applicable codes and standards, local and federal government regulations and conditions of environmental permits. It is recommended that Kuban GRES use the services of an engineering consultant with international experience to assist in the process. The Construction Manager's team will interface with the utility, the gas company, the oil supply company, the water supply company, the local government and the environmental authorities.

The Construction Managerwill hold monthly meetings at the site with the contractor personnel and will be responsible for overall progress and control of the project.

The Construction Manager will periodically review progress and critical issues of the project and request assistance in personnel and services through other members of the Project Development Team as required. The Construction Manager's team will also act as coordinators between the contractor and the utility's operating personnel who will work closely with the contractor's start up organization and will be responsible for taking over from the contractor the plant equipment and components.

2.7 Plant Operation and Management Plan

The objective of an operating and management plan is to ensure the plant is operated in a safe and reliable manner. An operating plan involves, as a minimum, the following subjects:

- Plant staffing and labor relations
- Personnel training
- Procedures development - including budget and cost control
- Spare parts and materials management
- Management of initial operation and turnover
- Plant maintenance: routine, annual and major maintenance and administering respective subcontracts

The project company, Kuban GRES, should develop the above programs with the assistance of consultants after commencement of construction.

2.7.1 Plant Staffing For Operation

It is recommended that the staffing be commenced one year prior to operation of the first simple cycle unit. The staffing should then be built up until full staffing levels are reached one year prior to the scheduled operation of Unit 2 combined cycle.

The permanent plant staffing levels recommended are contained in Figure 2.7-1. The duties of each functional title should be described in the company procedures manual to be prepared by Kuban GRES

2.7.2 Training of Operating and Maintenance Staff

It is recommended that Operation and Maintenance staff key personnel be provided formal training one year prior to the scheduled commercial operation of the first simple cycle units. The procurement contracts will include training requirements. The key operating and maintenance personnel will then be associated with the plant startup and receive on the job training prior to assuming commercial operation.

It is further recommended that Kuban GRES retain the services of an experienced foreign operating company for at least up to one year after the plant is in complete commercial operation. This is to provide for a smooth hands on training and will aid in development of a core operating staff.

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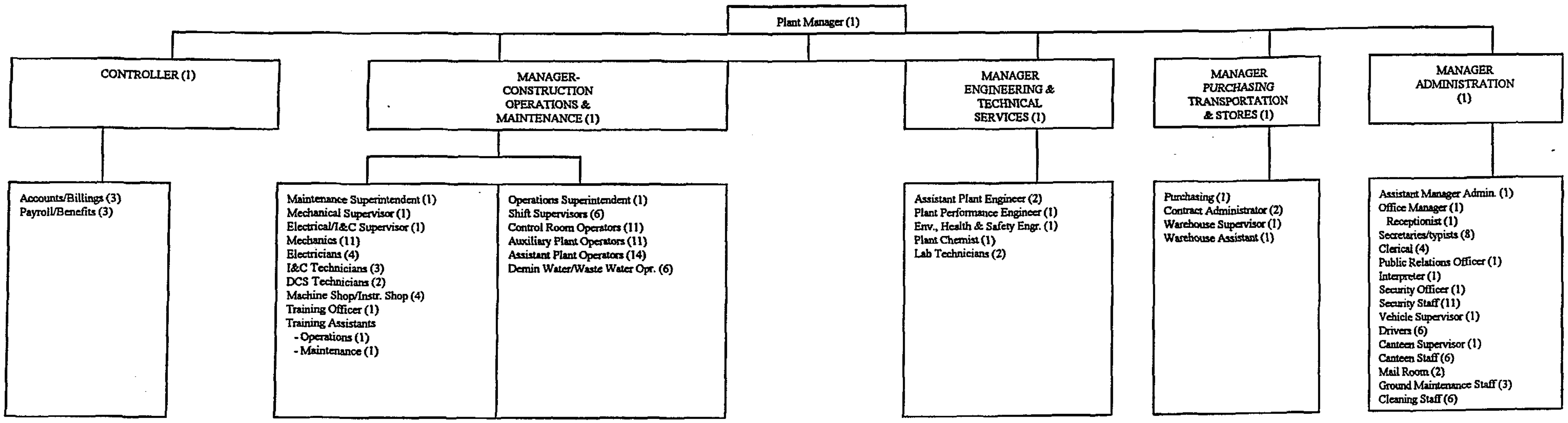
Figure 2.7-1
Proposed Organization for 900 MW Krasnodar GRES Plant



TOTAL PERSONNEL = 157

Plant Manager	1
Engineering	8
Operations & Maintenance	80
Purchasing	6
Finance/Accounts	7
Administration	55

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3.0 FINANCIAL AND ECONOMIC ANALYSIS

3.1 Financing Plan

3.1.1 Overview

The purpose of the financing plan is to combine the expected capital and operating costs and plant characteristics as detailed in Chapter 2, the required investments (domestic and foreign debt and equity), and the necessary investment returns (repayment of debt principal and interest, and distribution of dividends to equity shareholders) to help determine what level of tariff will be required to make the project feasible from a financial point of view. While the results of Chapter 2 provide an estimate of equipment and construction costs, a financing plan must also take account of working capital requirements and how these costs will be financed.

The preparation of a financing plan for the Krasnodar GRES plant involved the creation of a project-specific computer model with several modules. These modules have been designed for maximum flexibility to allow for a range of scenarios representing alternative capital structures, project definitions and risk factors. The details of the modules of the financial model, using the Base Case assumptions, are presented Appendix A. These modules include:

1. Financial Statements (Income Statement, Cash Flow Statement, Balance Sheet)
2. Assumptions
3. Project Costs
4. Debt Service
5. Working Capital
6. Depreciation and Capital Expenditures
7. Tax Worksheet

The primary goal in the design of the financial model is to consider various capital structures and the required tariff to satisfy the investor return requirements. International power projects such as this are often able to attract numerous and diverse sources of capital; however, because the capital markets in Russia are at an early stage of development, the options available to this project are limited. Four potential sources of capital were considered, and a brief outline of their relative advantages and disadvantages is shown below in Table 3.1-1.

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Table 3.1-1
Capital Structure Tradeoffs

	Advantages	Disadvantages
World Bank Debt	• Low cost of capital (8% interest rate) • Deferred interest and principal payments (5 year grace period)	• Fixed repayment schedule which must be adhered to over 12 year payback period • Sovereign guarantee required from the Russian government
Export Credit Agency Loan	• Low cost of capital (probably around 8% interest rate) • Deferred principal (probably a 3 year grace period for principal, but not for interest)	• Fixed repayment schedule which must be adhered to over 5 year payback period • Limited availability; probably only available from the U.S. and France • Sovereign guarantee required from the Russian government
Domestic Equity	• Most flexibility in terms of required rates of return and payback period • No fixed payments (as with a debt service schedule)	• Limited resources of the Russian Ownership Group • Escrow account covenants will probably be required (i.e., 6 months of debt service payments in escrow accounts due to limited creditworthiness of domestic equity investors)
Foreign Equity	• Experienced developer and operator of combined cycle technology can reduce operating risks • Industry precedent in Russia can increase the chance of attracting foreign equity to future projects in Russia • No fixed payments	• Higher cost of capital (foreign equity investors may expect returns between 25% and 35%) • Currency and country risk are high in Russia and are the reasons foreign equity investors expect high returns • Need for exit strategy (foreign equity investors will expect a quick payback period than domestic investors and will expect a method for cashing out their investment)

The Financing Plan description has been divided into three sections: 1) Base Case, 2) Capital Structure Sensitivity Analysis, and 3) Assumptions. The Base Case assumes a simple capital structure with the World Bank providing the only source of debt financing and the Russian Ownership Group providing the only source of equity. The second section presents a proposed capital structure and includes additional debt financing from vendors and/or export credit agencies (ECA's) and additional equity from a foreign strategic investor. This enhanced capital structure is then analyzed for several variables: project definition (allowing for the possibility of including the transmission line and gas pipeline), differing levels of supplemental debt and equity financing, and alternative levels of equity returns. Several scenarios are considered in order to help the Russian Ownership Group quantify and evaluate several key issues:

- Should foreign equity be included in the capitalization?
- What level of equity returns are possible, both for the Russian Ownership Group and for potential foreign investors?
- Should additional debt financing be included in capitalization?
- Should the project definition include or exclude the gas pipeline and transmission line?[1]

The third section presents each of the capital and operating assumptions incorporated in the Base Case financial model. Several of these assumptions are varied and their impact quantified in the Risk Analysis portion of this report.

3.1.2 Base Case Scenario

The Base Case assumptions result in a total project cost of $764 million (nominal US dollars) and a required one-part, levelized, busbar tariff, inclusive of value-added tax (VAT), of $0.0366 per kWh (1995 US dollars). For purposes of comparing this project to similar projects in economies devoid of VAT, this is equivalent to a levelized tariff of $0.0302 per kWh, net of VAT. Project definition is assumed to include all estimated costs associated with the construction of the 900 MW Krasnodar GRES plant and related financing costs, but does not include construction costs for the transmission line or gas pipeline necessary for operation of the plant. Expected sources of financing in the base case are $500 million in long-term debt from the World Bank and $264 million in equity from the Project Ownership Group. Key assumptions are shown in Table 3.1-2 below, and full details are provided in Appendix A.

After presenting the Base Case scenario results to members of the Russian Ownership Group in January 1996, it was requested that a Modified Base Case scenario be considered incorporating several revised assumptions. These revised assumptions include:

- Exclusion of the Special Tax (1.5%) in January 1996, which reduces VAT from 21.5% to 20.0%.
- Reduction of Excise Taxes and Duties by $10 million based on the expectation that a larger portion of the equipment will be procured domestically than represented in Chapter 2.
- Reduction of Contingencies on Russian project components from 25% to 20% of base "overnight" costs.
- Limitations on use of internally-generated cash for financing construction during years 1999 and 2000 to no more than $25 million to avoid the risk of depending too heavily on early cash flows for successful completion of the combined cycle phase of construction. In this Modified Base Case, any excess internally-generated cash which

[1] Scenarios were developed to answer this question at the request of the Ownership Group. Posing this question does not imply support for including either the gas pipeline or the transmission line in the project definition.

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is not used for construction would be placed in a reserve fund until full plant operation begins.

- Additional capital requirements necessary to replace internally-generated cash which is to held in reserve would come from additional equity, resulting in a lower debt-to-equity ratio than in the Base Case.

The total project cost under these assumptions of the Modified Base Case is $804 million and the required one-part, levelized busbar tariff is $0.0365 per kWh inclusive of VAT, or $0.0300 per kWh net of VAT. This tariff is nearly identical to the required tariff in the Base Case: the lower leverage in the Modified Base Case creates upward pressure on the tariff, which the lower tax and contingency assumptions compensate with downward pressure on the tariff.

The project cost estimates have been prepared based on results of the Least Cost Investment Plan developed in Task 1 and on the results of the Project Technical Analysis developed in Task 2. Input was also provided by members of the World Bank team. The capital structure assumptions and two-part tariff structure have been prepared incorporating work conducted in Task 4.

Under the Base Case scenario, the estimated debt-to-equity ratio is 65:35. As stated, in order to provide for a 15% return on equity, the required tariff, when expressed as a one-part, levelized busbar tariff is $0.0366 per kWh (in 1995 US dollars), inclusive of VAT, This is a levelized, average busbar tariff which Kuban GRES would need to charge in order to meet the requirements of lenders and equity investors. In fact, it is proposed that the tariff be structured into two parts: a capacity charge and an energy usage charge. The two-part tariff required to meet the Base Case set of assumptions is included in Table 3.1-2. Under the Modified Base Case scenario, the estimated debt-to-equity ratio is 62:38 and the required tariff is $0.0365 per kWh.

Throughout this chapter, discussion concerning the Base Case scenario refers to Table 3.1-2, "Scenario: Base Case," and <u>not</u> to Table 3.1-2A, "Scenario: Modified Base Case."

Table 3.1-2
SCENARIO: BASE CASE

ESTIMATED PROJECT COSTS

	Nominal US$ ('000)	% Total
Base Project Cost*	$419,039	55%
Duties, Excise, VAT, Special Taxes	173,843	23%
Physical Contingencies	66,156	9%
Real Russian vs. US Escalation	51,829	7%
Inflation	46,221	6%
Interest Paid During Construction	0	0%
Capitalized Interest During Construction	77,171	10%
Principal Paid During Construction	0	0%
Working Capital (Years 1-4)	18,422	2%
Less: Internally-Generated Cash	(88,669)	-12%
Total Project Cost to be Financed	$764,011	100%

CAPITAL STRUCTURE

	Nominal US$ ('000)	% Total
Debt		
World Bank Loan	$500,000	65%
Equity		
Russian Equity (15% FIRR)	264,011	35%
Total Investment	$764,011	100%

REQUIRED TARIFF

	w/o VAT	w/ VAT
One Part Tariff		
Option 1: Average Tariff ($/kWh) ('95 US$)	$0.0302	$0.0366
Two Part Tariff		
Option 2a: Capacity Charge ($/kW/yr) ('95 US$)	$92.00	$111.78
Option 2b: Energy Charge ($/kWh) ('95 US$)	$0.0138	$0.0168

* Includes $1.5 million for office furniture and computer systems.

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Table 3.1- 2A
SCENARIO: MODIFIED BASE CASE

ESTIMATED PROJECT COSTS

	Nominal US$ ('000)	% Total
Base Project Cost*	$419,039	51%
Duties, Excise, VAT, Special Taxes	154,848	20%
Physical Contingencies	59,982	7%
Real Russian vs. US Escalation	51,829	6%
Inflation	45,248	6%
Interest Paid During Construction	0	0%
Capitalized Interest During Construction	77,200	9%
Principal Paid During Construction	0	0%
Working Capital (Years 1-4)	18,386	2%
Less: Internally-Generated Cash**	(22,115)	-3%
Total Project Cost to be Financed	$804,417	100%

CAPITAL STRUCTURE

	Nominal US$ ('000)	% Total
Debt		
World Bank Loan	$500,000	62%
Equity		
Russian Equity (15% FIRR)	304,417	38%
Total Investment	$804,417	100%

REQUIRED TARIFF

	w/o VAT	w/ VAT
One Part Tariff		
Option 1: Average Tariff ($/kWh) ('95 US$)	$0.0300	$0.0365
Two Part Tariff		
Option 2a: Capacity Charge ($/kW/yr) ('95 US$)	$92.00	$111.78
Option 2b: Energy Charge ($/kWh) ('95 US$)	$0.0138	$0.0168

* Includes $1.5 million for office furniture and computer systems. The Base Project Cost includes $39.5 million for the Civil Works package (See Table 2.4-1A).
** Any additional internally-generated cash is held in a reserve fund until after construction and full plant operation begins.

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World Bank Loan

The Base Case, and all scenarios in the Capital Structure Sensitivity Analysis section, assumes a World Bank loan in the amount of $500 million with a fixed interest rate of 8%, a five year grace period for principal payments, interest paid during the grace period only after startup of operations, and a 17 year term from the time of project inception. Table 3.1-3 indicates key features of this assumed loan under the Base Case. An annual debt amortization schedule is presented in Table 3.1-4, with further detail provided in the detailed financing plan in Appendix A.

During the construction period, interest is calculated on all outstanding loan principal amounts. This figure is "Interest Accrued". Under the terms of the World Bank loan, it will not be necessary to pay these interest costs until the project is completed. Instead of paying the "Interest Accrued" during the project construction period this amount of interest is capitalized -- it is added to the amount of outstanding principal. This figure is called "Capitalized Interest During Construction." For other loans that do not offer a five year grace period (such as the export credit agency loan and commercial bank loan shown in the capital structure scenarios, discussed below), it is necessary to pay the "Interest Accrued" as soon as incurred. In that case, the amount that must be paid during the construction period is called "Interest Paid During Construction."

Table 3.1-3
WORLD BANK LOAN TERMS

Total Loan Amount ($000)	$500,000
Issue Date	12/1/96
First Drawdown Amount	$31,797
First Drawdown Date	12/1/96
First Interest Payment	12/1/01
Second Drawdown Amount	$101,271
Second Drawdown Date	12/1/97
First Interest Payment	12/1/01
Third Drawdown Amount	$163,668
Third Drawdown Date	12/1/98
First Interest Payment	12/1/01
Fourth Drawdown Amount	$126,094
Fourth Drawdown Date	12/1/99
First Interest Payment	12/1/01
Capitalized Interest	$77,171
First Principal Payment	12/1/01
Last Principal Payment	12/1/13
Fixed Interest Rate (%/year)	8.0%

- $500 million draw-down during construction.
- Can be used to finance equipment (which is procured through international competitive bidding), contingencies, escalation costs, inflation costs, and interest during construction. Can also finance equipment procured through other approved bank procurement methods.
- Cannot be used to finance taxes, duties, or equipment which is not procured through international competitive bidding.
- 5 year grace period for repayment of principal . Interest capitalized during construction period.
- 8% interest rate, compounded annually. Actual interest rate may be lower, but lender transaction fees are imbedded in assumed 8% interest rate.
- Interest payable semi-annually.
- 17 year term to maturity.
- Principal amortized, at option of borrower, on straight-line basis in equal semi-annual installments or in equal semi-annual installments of principal and interest.
- Commitment, mobilization and other fees estimated at 2% of principal amount of loan payable at time of closing.
- Other terms and conditions subject to negotiation and may include covenants specifying minimum debt/equity ratio, cash balances, interest coverage ratios, etc. during the loan repayment period.

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Table 3.1-4
WORLD BANK LOAN AMORTIZATION SCHEDULE

Year Ending	Applied to Principal	Interest Accrued	Interest Paid	Capitalized Interest	Debt Service	Principal Outstanding	Loan Drawdown
12/31/95	0	0	0		0	0	0
12/31/96	0	202	0	202	0	31,999	31,797
12/31/97	0	3,204	0	3,204	0	136,473	101,271
12/31/98	0	11,958	0	11,958	0	312,099	163,668
12/31/99	0	25,701	0	25,701	0	463,894	126,094
12/31/00	0	36,106	0	36,106	0	500,000	0
12/31/01	38,462	40,000	40,000	0	78,462	461,538	0
12/31/02	38,462	36,923	36,923	0	75,385	423,077	0
12/31/03	38,462	33,846	33,846	0	72,308	384,615	0
12/31/04	38,462	30,769	30,769	0	69,231	346,154	0
12/31/05	38,462	27,692	27,692	0	66,154	307,692	0
12/31/06	38,462	24,615	24,615	0	63,077	269,231	0
12/31/07	38,462	21,538	21,538	0	60,000	230,769	0
12/31/08	38,462	18,462	18,462	0	56,923	192,308	0
12/31/09	38,462	15,385	15,385	0	53,846	153,846	0
12/31/10	38,462	12,308	12,308	0	50,769	115,385	0
12/31/11	38,462	9,231	9,231	0	47,692	76,923	0
12/31/12	38,462	6,154	6,154	0	44,615	38,462	0
12/31/13	38,462	3,077	3,077	0	41,538	0	0

Financial Internal Rate of Return

To calculate the financial internal rate of return for the project (FIRR), project cash flows before financing costs using the Base Case busbar tariff of $0.0366 per kWh (inclusive of VAT) were discounted to arrive at nominal FIRR of 12%. Project cash flows before financing, or net free cash flows, are cash flows from operations, after investments and before financing cash flows. Financing cash flows include debt drawdown and repayment and interest payments as well as equity contributions and dividends paid to equity shareholders. The FIRR converted to a real basis (without the effect of inflation) is 9.9%. Table 3.1-5 below summarize these calculations; more detail is included in Appendix A, page 13.

Table 3.1-5
Project FIRR Calculations ('000 Nominal US $)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Cash Flows After Operations and Investments	(51,853)	(167,707)	(277,819)	(230,527)	(23,819)	49,865	94,800	97,307	99,757	77,753
Plus: Interest Expense	202	3,204	11,958	25,701	36,106	40,000	36,923	33,846	30,769	27,692
Net Free Cash Flow, Project Before Financing	(51,650)	(164,503)	(265,860)	(204,826)	12,287	89,865	131,723	131,153	130,527	105,446
Project FIRR, Nominal	**12.0%**									
Project FIRR, Real (less average inflation)	**9.9%**									

In order to calculate the FIRR of the project using current tariffs, a weighted average wholesale tariff was calculated for the three main power generation plants in the North Caucasus, as shown below in Table 3.1-6. The average tariff, weighted by generation levels, which was approved by the Federal Energy Commission (FEC) is 97.6 Rubles per kWh. The resulting FIRR is low (2.5% in nominal terms, 0.4% in real terms), which is not surprising since Russian tariffs do not provide for sufficiently high valuations of the replacement cost of assets. Alternatively, if the tariffs requested by RAO EES Rossii had been accepted by the FEC, and if this higher weighted average tariff were applied to the Krasnodar GRES plant, the resulting FIRR would be considerably higher (11.1% in nominal terms, 9.0% in real terms).

Table 3.1-6
Project FIRR Under Current Tariffs

Three Main Power Plants in North Caucasus	4th Quarter 1995 Wholesale Price (Rubles per kWh): Approved by Federal Energy Commission	4th Quarter 1995 Wholesale Price (Rubles per kWh): Requested by RAO EES Rossii	4th Quarter 1995 Generation (GWh)
Stavropolskaya	80	120.6	3,409
Novosherkasskaya	123	154.4	2,944
Nevinomysskaya	90	1200	2,071
Weighted Average	97.6	132.3	
Project FIRR			
Nominal	2.5%	11.1%	
Real	0.4%	9.0%	

Return on Assets

Return on assets (ROA) was calculated using several approaches. ROA was calculated on both a before-tax and after-tax basis. However, because the project has a finite life of 35 years, and capital expenditures to replace assets have not been considered, a calculation based on net assets will show ROA increasing in later years. Therefore, the ROA calculation was also performed using average gross assets. For both gross and net assets, the balance sheet amount was adjusted by inflation to allow for replacement cost considerations. A summary of the resulting calculations is shown below in Table 3.1-7 with further detail provided in Appendix A, page 10.

Table 3.1-7
ROA Calculations

	2001	2002	2003	2004	2005	2006	2007	2008
Operating Return on Gross Assets	7.9%	7.8%	7.8%	7.8%	7.7%	7.6%	7.5%	7.4%
Net Return on Gross Assets	2.3%	2.5%	2.8%	3.1%	3.2%	3.4%	3.6%	3.7%
Operating Return on Net Assets	8.7%	8.9%	9.3%	9.7%	10.0%	10.4%	10.8%	11.2%
Net Return on Net Assets	2.5%	2.9%	3.3%	3.8%	4.2%	4.7%	5.2%	5.7%

3.1.3 Capital Structure Sensitivity Analysis

While the Base Case assumes a simplified capital structure, the Ownership Group will probably consider other options as the project proceeds. The optimal capital structure depends on the investment limitations of some of the Ownership Group participants, the desirability of involving experienced developers and combined cycle operators as equity participants, the availability of capital from foreign sources, and the possibility of raising additional financing through equipment vendors with export credit agency (ECA) support and commercial banks. These trade-offs were outlined above in Table 3.1-1. This sections provides some analysis of alternative capital structures.

A total of nine capital structures were considered, as listed below in Table 3.1-8. The summary of these scenarios is presented in Tables 3.1-9 and 3.1-10.

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Table 3.1-8
Key to Capital Structure Scenarios

Case 1 -- Base Case
Case 2 -- $100 million ECA Loan
Case 3 -- $50 million Foreign Equity
Case 4 -- $100 million ECA Loan, $50 million Foreign Equity
Case 5 -- 77/23 Debt Equity Ratio, $100 million ECA Loan, $37 million Commercial Bank Loan, $50 million Foreign Equity

Case 6 -- 25% Returns for Russian and Foreign Equity, $50 million Foreign Equity

Case 7 -- 70/30 Debt Equity Ratio, $48 million ECA Loan

Impact of Including Transmission Line and Gas Pipeline

Case 8 -- Base Case Including Transmission Line
Case 9 -- Base Case Including Transmission Line and Gas Pipeline

Additional debt through vendor financing is modeled using relatively conservative assumptions: an eight year term with a three year grace period, 8% fixed interest rate, and straight-line amortization. Based on discussions with the U.S. Export Import Bank, export financing would likely be available under these terms for U.S.-sourced equipment. Initial discussions with some export credit agencies indicate that ECA financing may be limited to the U.S. and France. Furthermore, this type of debt financing, like the World Bank loan, requires a sovereign Russian guarantee for the applicable amount. Additional debt, perhaps through a commercial bank or private placement source, is also considered in Case 5. The terms assumed for such a loan are similar to an ECA loan, but at higher interest rates of 12%.

Cases 2 and 4 assume a $100 million ECA loan. Cases 5 and 7 also assume an ECA loan (Case 5 additionally incorporates a commercial bank loan) to model the following capital structures:

- A debt/equity structure of 70/30 (Case 7)
- A debt/equity structure with the maximum debt (Case 5) which, based on results of the financial model, was 77/23. A higher portion of debt provides unsolvable constraints on the financial model.

Cases 3 through 6 assume a foreign equity investment of $50 million. As outlined in the discussion above on capital structure trade-offs in Table 3.1-1, foreign equity investors will expect higher returns to compensate for the additional country and currency risk. For modeling purposes, it was assumed that such an investor might expect returns of approximately 28%. Actual equity investment terms would depend on negotiations with

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the Ownership Group and the willingness of foreign investors to consider this project. It may be necessary for even higher returns to be offered to attract foreign equity investors, perhaps as high as 35%. Case 6 illustrates the results of a capital structure in which both Russian and foreign equity investors receive identical returns of 25%. A summary of results from Cases 1 through 7 is presented in Table 3.1-9 below, and more detailed results of these scenarios are presented in Appendix A, pages 92 through 138.

Impact of Including the Gas Pipeline and Transmission Line

Inclusion of the gas pipeline and the transmission line to the project definition adds significantly to the total project cost, to the amount of required investment from the Russian Ownership Group, and to the required tariff. This is illustrated in Cases 8 and 9 and the results of these scenarios are shown in Table 3.1-10 below. These two scenarios use the same set of capital structure assumptions as the Base Case (Case 1); that is, a $500 million World Bank loan and the remaining capital provided by domestic equity. These cases are presented to illustrate the additional tariff required to cover the capital expenditure requirements associated with Project but not directly included in the Project. It is not recommended that the Project include either the transmission line or the gas pipeline; however, construction of both is a prerequisite for startup operations of the plant.

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Table 3.1-9
Summary of Capital Structure Scenarios
Without Transmission Line or Gas Pipeline

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
Project Cost (million US$)	$764 million	$823 million	$760 million	$798 million	$823 million	$749 million	$783 million
Transmission Line Included?	No	No	No	No	No	No	No
Gas Pipeline Included?	No	No	No	No	No	No	No
Capital Structure (million US$)							
Debt							
World Bank Loan	$500	$500	$500	$500	$500	$500	$500
ECA Loan	$0	$100	$0	$100	$100	$0	$48
Commercial Bank Loan	$0	$0	$0	$0	$37	$0	$0
Equity							
Russian Investors	$264	$223	$210	$148	$135	$199	$235
Foreign Investors	$0	$0	$50	$50	$50	$50	$0
Cost of Capital							
Debt – Interest Rate							
World Bank Loan	8%	8%	8%	8%	8%	8%	8%
ECA Loan	--	8%	--	8%	8%	--	--
Commercial Bank Loan	--	--	--	--	12%	--	--
Equity – Rates of Return							
Russian Investors	15%	15%	15%	15%	15%	25%	15%
Foreign Investors	--	--	28%	28%	28%	25%	--
Debt/Equity Ratio	65/35	73/27	66/34	75/25	77/23	66/34	70/30
Average Tariff (w/o VAT)	$ 0.0302	$ 0.0297	$ 0.0323	$ 0.0323	$ 0.0323	$ 0.0375	$ 0.0299
Average Tariff (w/ VAT)	$ 0.0366	$ 0.0361	$ 0.0393	$ 0.0392	$ 0.0393	$ 0.0456	$ 0.0364

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Table 3.1-10
Summary of Capital Structure Scenarios
With Transmission Line and Gas Pipeline

	Case 8	Case 9	Modified Base Case
Project Cost (million US$)	$902 million	$973 million	$804 million
Transmission Line Included?	Yes	Yes	No
Gas Pipeline Included?	No	Yes	No
Capital Structure (million US$)			
Debt			
World Bank Loan	$500	$500	$500
ECA Loan	$0	$0	$0
Commercial Bank Loan	$0	$0	$0
Equity			
Russian Investors	$402	$473	$304
Foreign Investors	$0	$0	$0
Cost of Capital			
Debt -- Interest Rate			
World Bank Loan	8%	8%	8%
ECA Loan	--	--	--
Commercial Bank Loan	--	--	--
Equity -- Rates of Return			
Russian Investors	15%	15%	15%
Foreign Investors	--	--	--
Debt/Equity Ratio	55/45	51/49	62/38
Average Tariff (w/o VAT)	$0.0341	$0.0363	$0.0300
Average Tariff (w/ VAT)	$0.0415	$0.0441	$0.0365

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3.1.4 Assumptions

Macroeconomic Assumptions

The financial model was prepared based on the following macroeconomic assumptions:

- For international inflation projections, the Index of Unit Value of Manufactured Exports (MUV) is used as of May 1995. This index was provided by the World Bank, and is calculated for the G-5 industrial countries (France, Germany, Japan, the United Kingdom and the United States.).

Table 3.1-11
INTERNATIONAL INFLATION

1996	1997	1998	1999	2000	2001	2002	2003	2004 and beyond
2.0%	1.6%	2.1%	2.4%	2.2%	2.5%	2.3%	2.0%	2.1%

- The units in the financial model are nominal U.S. dollars. Nominal (inclusive of inflationary effects) rather than real (exclusive of inflation) units are used since an important objective of the model is to facilitate a financial decision regarding a World Bank loan and the associated debt service schedule.

- Russian labor, material and equipment costs have been adjusted using the real escalation factors provided from Task 2, shown below. These real adjustments are net of inflation effects.

Table 3.1-12
RUSSIAN VS. U.S. REAL COSTS

	1995	2000	2005	2010	2015	2020	2025	2026 and beyond
Material	70.0%	85.0%	87.5%	90.0%	93.1%	96.3%	99.4%	100.0%
Equipment	50.0%	60.0%	75.0%	90.0%	93.1%	96.3%	99.4%	100.0%
Labor cost	10.0%	30.0%	60.0%	73.3%	86.7%	100.0%	100.0%	100.0%
Labor productivity	50.0%	60.0%	70.0%	80.0%	90.0%	100.0%	100.0%	100.0%
Labor -- Total Cost	20.0%	50.0%	85.7%	91.7%	96.3%	100.0%	100.0%	100.0%

RUSSIAN VS. U.S. REAL ESCALATION FACTORS

	1995	2000	2005	2010	2015	2020	2025	2026 and beyond
Equipment	1.00	1.20	1.50	1.80	1.86	1.93	1.99	2.00
Material	1.00	1.21	1.25	1.29	1.33	1.38	1.42	1.43
Labor	1.00	2.50	4.29	4.58	4.81	5.00	5.00	5.00

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Capital Expenditures

- The project costs are defined to include the 900 MW combined cycle generation plant at the Mostovskoy site, and do not to include the transmission lines or the gas pipeline. Details of the base project costs are shown Table 3.1-13. These costs, developed in Tasks 1 and 2, do not include Owner's costs, real or inflation escalation factors, financing costs, contingencies, duties, excise tax, value-added tax or special taxes. These additional costs are incorporated in the financial model separately.

- In the Modified Base Case, the Civil Works cost is increased to $39.5 million and the Indirect Costs reduced to $60.3 million resulting in the same total project cost (see Table 2.4-1A).

- It is assumed that construction of the transmission line necessary for distributing the newly generated power to the grid will be the responsibility of the regional or national unified power system, and that these capital costs will be included in retail prices charged by the local distribution company, Kubanenergo. It should be noted that while the economic model does include incremental transmission line costs in the economic cost/benefit analysis, the Base Case scenario of the financial model does not include these costs. It is also assumed that the construction of the gas pipeline to the project site will be the responsibility of Gazprom, and that these capital costs will be reflected in the price of gas charged to the project. The additional estimated costs for these two items, excluding escalation, taxes and financing costs, are shown in Table 3.1-14. An important assumption in the base case scenario is that the transmission line and gas pipeline are completed on schedule to facilitate timely startup of the Krasnodar GRES plant.

- Duties and excise taxes have been applied to all non-Russian capital costs, and have been estimated at 20%. Value-added tax (VAT) and special tax are applied similarly and total 21.5% of the taxable base.[2] It is assumed that VAT paid during the construction phase, and prior to generation of revenues, is allowed to be valued as a deferred tax credit against future VAT obligations from revenue. This assumption can be examined in detail in tax worksheet of the financial model, Appendix A, pages 85-91. Assets financed by loans granted by the governments of foreign states or by international financial agencies are imported into Russia or when the imported assets qualify as "imported technology," these assets receive a VAT exemption. However, members of the Ownership Group indicated that this exemption was unlikely based on other recent precedents. The base case scenario assumes that non-Russian equipment does not qualify for such a VAT exemption. Since the tax regulations in Russia are often contradictory and are difficult to interpret, the Ownership Group should request a tax interpretation from the Russian tax authorities. . In applying VAT and the special

[2] After the financial scenarios were produced and presented to the Ownership Group, the Russian government revoked the 1.5% Special Tax. This is not reflected in the financial model, except for the Modified Base Case. The elimination of the Special Tax reduces the total project cost by approximately $8 million.

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tax to imports, the tax base is the customs value, plus customs duty and excise duty when applicable. Table 3.1-15 shows the tax calculations for the base case scenario using the assumptions described.

Table 3.1-13
Base Project Costs ("Overnight Cost")

'000 1995 US dollars	Russian					Non-Russian			Total
	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	
Civil Works	0	9,092	7,883	0	16,975	0	0	0	16,975
Combustion Turbine	0	0	440	0	440	120,000	0	120,000	120,440
HRSG	0	0	1,760	0	1,760	34,500	0	34,500	36,260
Steam Turbines	0	0	165	0	165	27,000	0	27,000	27,165
Distribution Control Systems	0	0	0	0	0	2,900	0	2,900	2,900
Mechanical Package	20,496	11,205	5,137	0	36,838	26,000	0	26,000	62,838
Electrical Package	14,980	7,545	4,718	0	27,243	0	0	0	27,243
Switchyard	3,200	1,440	6,400	0	11,040	29,818	0	29,818	40,858
Engineering/Project Management	0	0	0	29,010	29,010	0	53,850	53,850	82,860
Total Plant	38,676	29,282	26,503	29,010	123,471	240,218	53,850	294,068	417,539

Table 3.1-14
Base Project Costs ("Overnight Costs")

'000 1995 US dollars	Russian					Non-Russian			Total
	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	
Transmission Line	6,545	20,545	14,000	4,545	45,636	20,091	0	20,091	65,727
Gas Pipeline	0	0	9,400	3,500	12,900	25,100	0	25,100	38,000

Table 3.1-15
Duties and Taxes
(Applicable to Generation Plant Only)

'000 1995 US dollars	Russian					Non-Russian			Total
	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	
Duties/Excise Taxes	0	0	0	0	0	48,044	10,770	58,814	58,814
VAT/Special Tax[3]	11,453	8,768	0	11,352	31,573	68,174	15,283	83,456	115,029
Total	11,453	8,768	0	11,352	31,573	116,218	26,053	142,270	173,843

[3] After the results of the financial model were produced, the Russian government rescinded the Special Tax of 1.5%. This will reduce tax costs by approximately $8 million, which has not been deducted from the figures shown here.

- Physical contingencies are included in total project costs, based on a 25% contingency for Russian costs and 10% contingency for non-Russian costs. These figures are shown in Table 3.1-16.[4]

- The timing of capital expenditures cash outflows is shown in Table 3.1-17.

- The total project costs, net of financing costs and working capital, are shown in Table 3.1-18 by year of expected expenditure and total $755 million. Additionally, the Base Case scenario allows for $1.5 million for office furniture and computers systems, not reflected in Table 3.1-18. Financing costs and working capital require an additional $96 million. Contingency costs, described in the Task 2 section of the report, are also included in these numbers. The escalation referred to in the table is the inflation escalation and Russian versus U.S. real escalation referred to above in the subsection on "Macroeconomic Assumption."

- The average assumed depreciable lives of fixed assets of the plant is 25 years, based on an estimated average currently used for Russian power sector assets. Depreciation is calculated on a straight line basis. The financial model assumes maintenance but no replacement of assets beyond capital repairs, and the assumed life of the project is 35 years from the time of startup of combined cycle operations (estimated to begin at full capacity in the year 2000).

Table 3.1-16
Physical Contingencies
(Applicable to Generation Plant Only)

	Russian					Non-Russian			
'000 1995 US dollars	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
Physical Contingencies	9,669	7,321	6,626	7,253	30,868	28,826	6,462	35,288	66,156

Table 3.1-17
Expenditure Profile

	Project Year					
	1996	1997	1998	1999	2000	Total
Generation Plant Expenditure Schedule	5%	22%	33%	28%	12%	100%

[4] The Modified Base Case uses a revised assumption of 20% physical contingencies for Russian components.

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Table 3.1-18
Total Project Costs
(excluding financing costs and working capital)
(figures are '000)

	1996	1997	1998	1999	2000
Non-Russian Equipment (non-escalated)	$21,143	$86,137	$125,287	$107,669	$45,026
Non-Russian Indirect (non-escalated)	4,740	19,309	28,086	24,136	10,093
Non-Russian Subtotal (inflation escalated)	$26,401	$109,276	$162,281	$142,808	$61,034
Russian Equipment (real escalated)	$3,327	$13,978	$20,936	$18,517	$7,963
Russian Materials (real escalated)	2,524	10,852	15,950	14,133	6,088
Russia Labor (real escalated)	2,322	10,942	19,084	18,453	8,518
Russian Indirect (real escalated)	2,794	12,815	20,591	19,272	8,680
Russian Subtotal (real & inflation escalated)	$11,186	$50,352	$81,008	$76,250	$34,603
Total Project Costs (real & inflation escalated)	$37,587	$159,628	$243,289	$219,058	$95,637

- Internally generated cash during the construction period reduces the amount of required external financing by $89 million. Because the plant begins operating and creating revenues before the end of the five year startup period, when the plant is operating as a simple cycle plant but before operating at full capacity as a combined cycle plant, some revenues are available to fund the last part of the construction period. To avoid the risk of depending too heavily on early cash flows for successful completion of the combined cycle phase of construction, a Modified Base Case is included which imposes limitations on the use of internally-generated cash for financing construction during years 1999 and 2000 to no more than $25 million. The results of this Modified Base Case are shown in Table 3.1-2A. Internally-generated cash, if any, which is not used for construction would be placed in a reserve fund until full plant operation begins. Additional capital requirements will be necessary to replace internally-generated cash which is to be held in reserve and would come from additional equity, resulting in a lower debt-to-equity ratio than in the Base Case.

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Operating Parameters

- The operating assumptions are based on the expectation that contract award will begin December 1, 1996, and that the project is completed on time. The assumptions regarding timing of construction and capacity coming on-line are shown in Table 3.1-19. For instance, in 1998, it is assumed that the first module of gas turbine generating units with 300 MW of capacity begins operating December 1, 1998. By December 1, 1999, the first module of simple cycle capacity is converted to combined cycle. Full capacity is assumed to be realized by June 1, 2000.

- While operating in the simple cycle, gas turbine mode, the plant is assumed to be dispatched as peak load facility, therefore the assumed load capacity in this mode is 40%. When combined cycle capacity is available, it is assumed the plant will be base loaded, with planned outages for maintenance and a load capacity of 80%.[5] Beginning in year 2010, the load factor is reduced by 1.5% from the previous year's level as the generating plant ages, eventually falling to a 50% load factor.

- The heat rate, fuel consumption levels and assumed gas costs are shown in Table 3.1-20. The gas costs shown below are net of VAT (VAT is included in the financial model, but is calculated in a separate tax module), and are based on current gas costs of $61 (1995 US dollars) per 1,000 cubic meters. This cost is assumed to escalate at international inflation levels for ten years, after which time it is assumed to escalate in real terms at the rate of one percent per annum. A more conservative gas cost scenario is presented in the Risk Analysis section.

[5] The economic model, discussed later in this chapter, assumes a 90% load factor, which is based on assumptions from the Least Cost Plan. The financial model, however, uses a more conservative load factor of 80%.

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Table 3.1-19
ASSUMED GENERATION PARAMETERS

	1998	1999	2000	2001 and beyond
Nominal Capacity (MW) - GT, 1st module	300	300	0	0
Net Rated Capacity (MW) - GT, 1st module	295	295	0	0
Nominal Capacity (MW) - GT, 2nd module	0	300	300	0
Net Rated Capacity (MW) - GT, 2nd module	0	295	295	0
Nominal Capacity (MW) - CC, 1st module	0	450	450	450
Net Rated Capacity (MW) - CC, 1st module	0	443	443	443
Nominal Capacity (MW) - CC, 2nd module	0	0	450	450
Net Rated Capacity (MW) - CC, 2nd module	0	0	443	443
Total Nominal Capacity	300	750	900	900
Total Net Rated Capacity	295	738	886	886
Months of Operation - GT mode, 1st module	1	11	0	0
Months of Operation - GT mode, 2nd module	0	7	5	0
Months of Operation - CC mode, 1st module	0	1	12	12
Months of Operation - CC mode, 2nd module	0	0	7	12
Load Factor - GT mode	40%	40%	40%	40%
Load Factor - CC mode	80%	80%	80%	80%
Operating Hours per Year - GT, 1st module	292	3,212	0	0
Operating Hours per Year - GT, 2nd module	0	2,044	1,460	0
Operating Hours per Year - CC, 1st module	0	584	7,008	7,008
Operating Hours per Year - CC, 2nd module	0	0	4,088	7,008
Production (GWh) - GT mode	88	1,577	438	0
Production (GWh) - CC mode	0	263	4,993	6,307
Total Production (GWh)	88	1,840	5,431	6,307
Supplied (GWh) - GT mode	86	1,552	431	0
Supplied (GWh) - CC mode	0	259	4,916	6,209
Total Supplied (GWh)	86	1,811	5,347	6,209

GT -- gas turbine, CC -- combined cycle

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Table 3.1-20 FUEL CONSUMPTION ASSUMPTIONS

		1998	1999	2000	2001
Heat Rate (Btu/kWh, LHV[1])	10,080				
Heat Rate (Btu/kWh, LHV)	6,771				
Gas - million 1,000m^3		0.025	0.501	1.083	1.210
Cost (per 1,000m^3) unescalated		$61.00	$61.00	$61.00	$61.00
Cost (per 1,000m^3) escalated		$64.54	$66.09	$67.55	$69.23
Variable Fuel Cost ($/kWh) nominal		$0.0184	$0.0180	$0.0135	$0.0133

[1] - Assumes energy content of 35,288 Btu per cubic meter.

- The operating and maintenance (O&M) cost calculation assumptions are shown in Table 3.1-21. The costs segregated into Russian and non-Russian components, based on estimates provided from Task 2.

- Variable and fixed O&M are assumed to consist of Russian labor, material and out-of-pocket expenses as well as non-Russian material and out-of-pocket expenses.

- Assumed losses for own use and auxiliary use amount to 1.56%. Transmission and distribution losses are assumed to equal 0% since the required tariff is calculated at the busbar.

Table 3.1-21
OPERATION AND MAINTENANCE CALCULATIONS

Fixed O&M Calculations	Total 1995 000 $	$/kW (886 MW)	1998	1999	2000	2001
Non-Russian Materials ($/kW/yr) (including duties)	$3,550	$4.0068	$5.0874	$5.2095	$5.3241	$5.4572
Non-Russian OOPs ($/kW/yr)	225	0.2540	0.2687	0.2751	0.2812	0.2882
Russian Materials ($/kW/yr) (with real material escalation)	360	0.4063	0.4852	0.5157	0.5463	0.5633
Russian Labor ($/kW/yr) (with real labor escalation)	935	1.0553	2.1933	2.5628	2.9214	3.4774
Russian OOPs ($/kW/yr) (with material/labor escalation)	405	0.4571	0.7479	0.8451	0.9400	1.07
Total Fixed O&M ($/kW/y)	$5,475	$6.1795	$8.7826	$9.4083	$10.0130	$10.8561

Variable O&M Calculations	Total 1995 000 $	$/MWh (6600 GWh)	1998	1999	2000	2001
Non-Russian Materials ($/kWh) (including duties)	$3,550	$0.5379	$0.00068	$0.00070	$0.00071	$0.00073
Non-Russian OOPs ($/kWh)	225.0000	0.0341	0.00004	0.00004	0.00004	0.00004
Russian Materials ($/kWh) (with material escalation)	760.0000	0.1152	0.00014	0.00015	0.00015	0.00016
Russian Labor ($/kWh) (with labor escalation)	35.0000	0.0053	0.00001	0.00001	0.00001	0.00002
Russian OOPs ($/kWh) (with material/labor escalation)	115.0000	0.0174	0.00003	0.00003	0.00004	0.00004
Total Variable O&M ($/kWh)	$4,685	$0.7098	$0.00090	$0.00093	$0.00096	$0.00099

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Working Capital

- Working capital assumptions are based on days-sales ratios, as shown in Table 3. 1-22. Some variations occur from the numbers shown below. For instance, cash requirements are much greater during the period of World Bank loan debt service, based on the assumption that debt service payments will need to be deposited in an escrow account 6 months prior to due date, and that payments are semi-annual. The Base Case scenario assumes a normalization of the customer payments problem by the year 2000, so that accounts receivable decreases from a current level of about 180 days sales to 45 days sales by 2000. A more conservative assumption, in which the payment problem takes an additional five years to be resolved, is examined in the Risk Analysis section. Inventory is assumed to include $2 million in backup fuel supplies and $6 million in spare parts. It is assumed that fuel will be metered at the plant, payable by the project a monthly basis in arrears.

Table 3.1-22
WORKING CAPITAL

	Long-Term Goal
Cash and cash equivalents (days sales)	3
Accounts Receivables (days sales)	45
Inventories (days sales)	18
Advances (days sales)	11
Other Current Assets (days sales)	2
Accounts Payables (days sales)	30
Other Current Liabilities (days sales)	5

Tax Assumptions

- A summary of the tax assumptions incorporated in the financial model are shown in Table 3.1-23. A brief discussion of value-added tax, special tax, duties and excise taxes is included in the subsection "Capital Expenditures," above. The following tax assumptions reflect the current status of Russian tax legislation and do not incorporate expectations concerning possible future changes to the tax regime, with the exception of the excess wages tax. It is assumed that, by the time the Krasnodar GRES plant is in operation, there will be no excess wages tax in effect. This assumption is based on currently proposed tax changes, which indicate that it is likely that the excess wages tax will be repealed for all taxpayers from January 1, 1996.

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Table 3.1.23
TAX ASSUMPTIONS

Type of Tax	Tax Basis	Rate
Profit Tax	Earnings before interest	35.0%
Value Added Tax	Gross revenue	20.0%
Special Tax	Gross revenue	1.5%[6]
Property Tax	Net fixed assets + inventory	1.5%
Duties/Excise Taxes	Imported equipment/materials	20.0%

Tariff

- The financial model solves for a levelized one-part busbar tariff which accommodates all of the assumptions described above and the capital structure parameters. The Base Case tariff is shown in Table 3.1-24. The levelized, average, one-part busbar tariff which Kuban GRES would need to charge in order to meet the requirements of lenders and equity investors is $0.0366 per kWh. This tariff is then converted into a two-part tariff structured to accomplish the goals described in the tariff recommendations of Task 4. Either the combined two-part tariff or the one-part tariff will result in the same equity returns. Some cash flow timing differences may result when instituting the two-part tariff.

Table 3.1-24
REQUIRED TARIFF -- BASE CASE

	w/o VAT	w/ VAT
One Part Tariff		
Option 1: Average Tariff ($/kWh) ('95 US$)	$0.0302	$0.0366
Two Part Tariff		
Option 2a: Capacity Charge ($/kW/yr) ('95 US$)	$92.00	$111.78
Option 2b: Energy Charge ($/kWh) ('95 US$)	$0.0138	$0.0168

[6] After the results of the financial model produced, the Russian government rescinded the 1.5% Special Tax. The Base Case scenario and capital structure sensitivity scenarios still reflect the Special Tax. The Modified Base Case shown in Table 3.1-2A was produced without the Special Tax.

3.2 Economic Rate of Return

3.2.1 Overview

The purpose of providing an economic analysis of the proposed project is to facilitate economically efficient planning and allocation of resources in the Russian electric power sector. In addition to the Least Cost Investment Plan of Task 1, an economic cost-benefit approach is employed in Task 3. A project-specific economic model was designed which subtracts economic costs of the project from its economic benefits, resulting in net economic benefits. The model then calculates the economic internal rate of return (EIRR) on this stream of net economic benefits.

Project costs are based on cost estimates from Task 2 and are adjusted, as necessary, for taxes, and real Russian cost escalation. Project benefits are measured by assuming that the new plant would be dispatched in accordance with a Least Cost Plan of Task 1, at current and projected tariff levels for each of four customer categories: Industry, Agriculture, Transport and Residential/Other[7]. A Base Case scenario is developed, as in the Financial Plan section of this report. The assumptions in the Base Case are tested for sensitivity to variations in: total electricity demand in the region, fuel costs, project startup delays, capital cost variations and other sensitivity cases. The net present value of cumulative project benefits less project costs are calculated each year, through the year 2034, using a 15% discount rate.

A detailed printout of the Base Case scenario of the economic model is included in Appendix B. The EIRR of the Base Case is 20.2%. The net present value, using the 15% discount rate, is $191.4 million. The Economic Rate of Return section has been divided into four sections: 1) Costs, 2) Benefits, 3) Base Case Results, and 4) Sensitivity Analysis. The economic model relies upon the project cashflows developed as inputs to the financial model in Task 3.1. These cost and benefit items are converted to economic values as discussed below. The measure of value for both cost and benefit streams is free foreign exchange (1995 US dollars).

3.2.2 Costs

Costs are segregated into capital costs and operating costs.

<u>Capital Costs</u>

- Russian Equipment and Construction Materials: These were taken as inclusive of shipping costs and exclusive of any taxes (including duties, excise tax, value-added tax, special tax and excess wages tax) and escalated with the factors obtained from Task 1.

[7] This fourth customer category, which includes "Other," is understood to encompass commercial customers as well as residential.

Table 3.2-1
Project "Overnight" Costs

'000 1995 US dollars	Russian					Non-Russian			Total
	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	
Civil Works	0	9,092	7,883	0	16,975	0	0	0	16,975
Combustion Turbine	0	0	440	0	440	120,000	0	120.000	120.440
HRSG	0	0	1,760	0	1,760	34,500	0	34,500	36,260
Steam Turbines	0	0	165	0	165	27,000	0	27,000	27,165
Distribution Control System	0	0	0	0	0	2,900	0	2,900	2,900
Mechanical Package	20,496	11,205	5,137	0	36,838	26,000	0	26,000	62,838
Electrical Package	14,980	7,545	4,718	0	27,243	0	0	0	27,243
Switchyard	3,200	1,440	6,400	0	11,040	29,818	0	29,818	40,858
Engineering/Project Management	0	0	0	29,010	29,010	0	53,850	53,850	82,860
Total Plant	38,676	29,282	26,503	29,010	123,471	240,218	53,850	294,068	417,539
Transmission Line	6,545	20,545	14,000	4,545	45,636	20,091	0	20,091	65,727
Total Project Costs	45,221	49,827	40,503	33,555	169,107	260,309	53,850	314,159	483,266

Table 3.2-2
Russian vs. U.S. Real Escalation Factors

	1995	2000	2005	2010	2015	2020	2025	2026 and beyond
Equipment	1.00	1.20	1.50	1.80	1.86	1.93	1.99	2.00
Material	1.00	1.21	1.25	1.29	1.33	1.38	1.42	1.43
Labor[1]	1.00	2.50	4.29	4.58	4.81	5.00	5.00	5.00

[1] Includes anticipated real wage and productivity adjustments.

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Table 3.2-3
Escalated Full Cost

'000 1995 US dollars	Russian					Non-Russian			Total
	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	
Civil Works	0	10,244	17,205	0	27,449	0	0	0	27,449
Combustion Turbine	0	0	960	0	960	120,000	0	120.000	120.960
HRSG	0	0	3,841	0	3,841	34,500	0	34,500	38.341
Steam Turbines	0	0	360	0	360	27,000	0	27,000	27,360
Distribution Control System	0	0	0	0	0	2,900	0	2,900	2,900
Mec' anical Package	22,920	12,625	11,212	0	46,756	26,000	0	26,000	72,756
Electrical Package	16,751	8,501	10,297	0	35,550	0	0	0	35,550
Switchyard	3,582	1,818	13,533	0	18,933	29,818	0	29,818	48,751
Engineering/Project Management	0	0	0	48,000	48,000	0	53,850	53,850	101,850
Total Plant	43,253	33,188	57,408	48,000	181,850	240,218	53,850	294,068	475,918
Transmission Line	7,108	22,439	26,040	6,709	62,296	20,091	0	20,091	82,387
Total Project Costs	50,361	55,627	83,448	54,710	244,146	260.309	53,850	314,159	558,305

The unescalated base costs are shown in Table 3.2-1, the escalation factors in Table 3.2-2, and the escalated full projects costs in Table 3.2-3.

- It should be noted that these are economic costs, and not financial costs. The transmission line is included in the economic analysis as this represents a use or resources that would not be required without the project. The gas pipeline is not included as its cost is assumed to be included in the gas price.

- Non-Russian Equipment and Construction Materials: These were taken at their financial cost, net of Russian taxes and international inflation. These are also included in Tables 3.2-1 and 3.2-3.

- Labor: This was estimated as Russian financial cost, adjusted by the escalation factors in Table 3.2-3 based upon Russian labor cost escalation and productivity forecasts.

Operating Costs

- Fuel: An economic cost of fuel of $50 per 1000 cubic meters was used. Fuel costs were escalated by one percent per year beginning in 2005.

- Labor: The labor input to operating costs was assumed to escalate in accordance with the escalation factors specified in Table 3.2-2.

- Local Materials: This input was also adjusted in accordance with the escalation factors in Table 3.2-2.
- Local Out of Pockets: This input was adjusted using an average of the labor and material escalation factor[8].
- Non-Russian Materials and Out of Pocket Expenses: These were taken at their financial cost as delivered, net of taxes, duties and international inflation.

3.2.3 Benefits

Dispatch Volumes

The plant's annual output is based on the results of Task 1. . The least cost model segregates its output into two categories-- that which meets incremental electricity demand in the region and that which substitutes for more costly power produced at other plants on the grid. The least cost dispatch model is run twice, once with the project included, and once as if the project were not undertaken, thus enabling an estimate of the amount of incremental demand served by the plant.

For economic analysis, output of the plant is valued net of transmission and distribution losses and own/auxiliary uses, which do not reach the consumer, as shown in Table 3.2-4.

[8] The equipment escalation factor was not incorporated in out of pocket expense estimates.

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Table 3.2-4
Electricity Available After Losses

	1998	1999	2000	2001 and beyond
Total Electricity Produced (GWh), Gross[1]	309	3,318	6,640	7,113
Total Electricity Produced (GWh), Net of 1.56% for Internal Use	305	3,266	6,537	7,002
Transmission & Distribution Losses (GWh), 13% of Unserved Energy	40	176	342	437
Total Electricity Available (GWh)	265	3,090	6,195	6,565

[1] The economic model assumes a 90% load factor which is based on assumptions from Task 1. The financial model uses a more conservative load factor of 80%. Some operating cost estimates from Taxk 2 assume a load factor of 85%.

Table 3.2-5
Breakout of Substituted and Unserved Energy

	1998	1999	2000	2001	2002	2003	2004	2005
Substituted Energy (GWh), before Transmission & Distribution Losses	0	1,914	3,904	3,638	3,173	2,247	1,068	372
Unserved Energy (GWh), after Transmission & Distribution Losses	265	1,177	2,291	2,927	3,331	4,137	5,163	5,768

Table 3.2-6
Savings from Substituted Energy

	1998	1999	2000	2001	2002	2003	2004	2005
Substituted Energy (GWh)	0	1,914	3,904	3,638	3,173	2,247	1,068	372
Savings from Substitution ($/kWh)	nm	0.0004	0.0034	0.0038	0.0039	0.0041	0.0043	0.0045
Savings from Substitution ($ '000)	0	777	13,561	13,654	12,488	9,229	4,559	1,654

Cost Savings for Substitution

It is assumed that no capacity additions besides the subject plant will be brought on line after 2000. Annual operating cost savings are estimated by comparing the operating costs of Krasnodar GRES with the average marginal operating cost of plants in the region (without Krasnodar GRES) as provided by Task 1 consultants. The breakout of energy produced by the subject plant which substitutes for costlier energy and which meets unserved energy requirements is shown in Table 3.2-5. The benefit of cost savings for substituted energy is shown in Table 3.2-6.

Customer Mix for Incremental Demand

The projected proportions of electricity consumption by each of the four customer categories in the Northern Caucasus Region as forecast for future periods by the Center for Energy Efficiency in Moscow were assumed to represent the mix of consumption of the project's output by customer classification. These proportions and levels of usage are shown in Table 3.2-7.

Demand by Customer Classification

The observable portion of the demand curve for each customer classification is at the price-quantity intersection. This intersection can be used to define a minimum benefit level, or willingness-to-pay, for each classification. The purchasing power parity factor for February through April 1995 was applied to the tariffs in effect at that time. The actual ruble tariffs and the purchasing parity factor are shown in Table 3.2-8.

Recent Tariff Changes

Tariffs are revised quarterly, and the latest information available is for tariffs in effect as of September 1995. The increase for September 1995 has brought tariffs into the range of average production costs. The only major exception is the residential/commercial class which remains under-priced at less than $0.02 per kWh.

Rationing of Power from the Grid

Forced outages are still used to ration power during peak periods. Presently, the forced outage policy of Kubanenergo is to disrupt the power supply only to industrial customers, but in a manner which usually can be anticipated by industrial customers.

Table 3.2-7
Customer Mix

	1998	1999	2000	2001	2002	2003	2004	2005
Percentages								
Industry	36.3%	37.0%	37.7%	38.0%	38.3%	38.8%	39.2%	39.7%
Agriculture	17.9%	17.7%	17.4%	17.3%	17.1%	17.0%	16.9%	16.7%
Transport	7.2%	7.3%	7.5%	7.5%	7.6%	7.8%	7.9%	8.0%
Residential	38.7%	38.0%	37.5%	37.2%	36.9%	36.5%	36.0%	35.6%
Projected Consumption In North Caucasus (GWh)								
Industry	16,235	17,119	17,912	18,598	19,363	20,160	20,989	21,896
Agriculture	7,998	8,159	8,289	8,495	8,664	8,851	9,041	9,238
Transport	3,218	3,381	3,551	3,698	3,865	4,040	4,223	4,414
Residential	17,319	17,569	17,817	18,204	18,650	18,959	19,285	19,629
Total	44,769	46,228	47,569	48,994	50,542	52,010	53,539	55,177

Table 3.2-8

	Tariff by Classification (as of September 1995, in Rubles) per kWh	PPP Ratio of Price Index (average Aug.-Oct. '95) Rubles : US$	Tariff by Classification (1995 US dollars) per kWh
Industry	298	4,293 : 1	0.0694
Agriculture	260	4,293 : 1	0.0606
Transport	298	4,293 : 1	0.0694
Residential/Other	84	4,293 : 1	0.0196

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Generally, there are few, if any, deliberate power disruptions to residential, agricultural or transport customers. This is a questionable policy from the perspective of economic efficiency. Therefore, the economic model has been run with the assumption that, even if the plant is not built, any outages in years after the plant could be on-line will be distributed across customer classes in proportion to their consumption.

3.2.4 Base Case Results

The EIRR calculated for the base case using the above-noted assumptions is 20.2%. The net present value at a 15% discount rate is $191 million. Results of the Base Case are shown in Table 3.2-9, and full details are included in Appendix B[9].

[9] The Base Case for the economic model does not incorporate assumptions for the owner's costs presented in Task 2. Further, the valuation approach for benefit from substituted energy does not incorporate the full variable costs of substituted energy (based on the average marginal cost of the regional system without the Mostovskoy plant). If the owners' costs were included, and if the benefit from substituted energy incorporated the full variable costs (in addition to the value of energy savings), then the EIRR would be higher. The EIRR under these revised assumptions would increase to 22.7%, or 2.5% higher than the Base Case, as shown. These modified results are not included in the Appendix, nor have they been used as a basis for comparison in the sensitivity scenarios.

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Table 3.2-9
Base Case Results

ECONOMIC RATE OF RETURN	**20.2%**
Net Present Value at 15% Discount Rate (1995 US $ '000)	$191,358

ECONOMIC BENEFIT SUMMARY

	1996-1997	1998	1999	2000	2001	2002	2003	2004	2005
Energy in GWh									
Quantity of Substituted Energy	0	0	1,914	3,904	3,638	3,173	2,247	1,068	372
Quantity of Incremental Energy	0	265	1,177	2,291	2,927	3,331	4,137	5,163	5,768
Energy Losses	0	40	176	342	437	498	618	771	862
Total Energy Supplied (GWh)	0	305	3,267	6,537	7,002	7,002	7,002	7,002	7,002
Benefits in 1995 US $ '000									
Benefit of Substituted Energy	$0	$0	$777	$13,561	$13,654	$12,488	$9,229	$4,559	$1,654
Benefit of Incremental Energy	0	12,866	57,571	112,708	144,459	164,911	205,759	257,947	289,556
Total Benefit of Energy Supplied	$0	$12,866	$58,348	$126,269	$158,113	$177,399	$214,988	$262,506	$291,210
ECONOMIC COST SUMMARY									
Total Capital Costs	$217,416	$166,050	$135,689	$39,150	$0	$0	$0	$0	$0
Total Production Costs	0	6,898	50,762	77,284	82,189	82,725	83,231	83,708	84,840
Total Costs	$217,416	$172,947	$186,451	$116,434	$82,189	$82,725	$83,231	$83,708	$84,840
ANNUAL NET BENEFIT	**($217,416)**	**($160,081)**	**($128,103)**	**$9,835**	**$75,925**	**$94,673**	**$131,758**	**$178,799**	**$206,370**

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3.2.5 Sensitivity Analysis Results

The following sensitivities were tested by recalculating the EIRR using assumptions that vary from the Base Case. A summary of the results of the scenarios is discussed below; full details are included in Appendix B, pages 28 through 47.

Table 3.2-10
Sensitivity Run Scenarios

Case 2.A -- Capital Cost Overruns Equal to Physical Contingencies ($71.3 million overrun)

Case 2.B -- Maximum Capital Cost Overruns to Yield EIRR of 15% ($278.5 million overrun)

Case 3.A -- Startup Delays of One Year for Simple Cycle and Combined Cycle

Case 3.B -- Startup Delays of One Year for Simple Cycle and Two Years for Combined Cycle

Case 4.A -- Fuel Cost Increase of 20% (from $50 to $60 per 1000 m3)

Case 4.B -- Maximum Fuel Cost With an EIRR of 15% (from $50 to $80 per 1000 m3, or 60% increase)

Case 5 -- Low Demand (per ICF Model)

Case 6 -- Minimum Tariff to Yield EIRR of 15% (tariffs decrease by 21% overall from current levels)

Case 2.A. -- Capital Cost Overruns Equal to Physical Contingencies

This sensitivity test of the economic rate of return assumes that the reserve for physical contingencies ($71.3 million, as estimated in the financial model, using assumptions from Task 2) are fully utilized. The result is an EIRR of 18.5%.

Case 2.B. -- Maximum Capital Cost Overruns to Yield EIRR of 15%

This sensitivity test employs the economic model to determine the maximum tolerance for capital cost overruns, given a 15% EIRR "hurdle rate".
If we assume that all of the other Base Case assumptions hold, capital costs can rise by as much as $278 million over projections and the EIRR remains above 15%.

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Case 3.A. -- Start up Delays of One Year for Simple Cycle and Combined Cycle

This scenario assumes a one-year delay in project output. Even without a commensurate slow-down in capital cost outlays, the EIRR remains above 20.0%.

Case 3.B. -- Start up Delays of One Year for Simple Cycle and Two Years for Combined Cycle

As in the case of the one-year delay (3.A.) this scenario was run without affecting base case capital outlays. The result of a one-year delay for simple cycle output and a two-year delay for combined cycle output is an EIRR of 18.3%.

Case 4.A. -- Fuel Cost Increase of 20%

This scenario tests the fuel cost assumption of the base case by adding 20% to the fuel cost during the entire operating period. The result of this scenario is an 18.3% EIRR.

Case 4.B. -- Maximum Fuel Cost With an EIRR of 15%

This scenario employs the economic model to determine the project's maximum tolerance for fuel price increases while retaining an EIRR of at least 15%. This model run demonstrates that, all other things equal, fuel costs equal to 160% of the base case assumption (or $80/1000m^3) could be tolerated.

Case 5 -- Low Demand

This scenario tests the possibility of a substantially lower consumer demand placed on the grid than that assumed in the base case. The low demand forecast outputs of the ICF model replace the base case assumptions. The downward effect on plant output under this scenario ends after 2000, based on the ICF model output. Therefore, the effect or EIRR is only to reduce the base case EIRR to 17.8%.

Case 6 -- Minimum Tariff to Yield EIRR of 15%

This scenario captures any downside contingencies that may exist in the base case as a result of the use of the current tariffs as a conservative measure of willingness to pay. These tariffs which were only established in September are substantially higher than the previous tariffs. This scenario demonstrates that an EIRR of 15% would be sustained even if actual willingness-to-pay is 21% lower than current tariffs.

3.3 Risk Factors

3.3.1 Overview

The Base Case financial and economic models and the economic model are predicated on various assumptions, discussed in Sections 3.1 and 3.2. The uncertainty of certain assumptions represent potential risks to investors and lenders in the project. Key risk factors are identified in this section. The financial model was used to quantify the possible financial impact of changes in key risk factors on credit quality and tariff. The results of these sensitivity analyses are shown in the tables in this section to provide a sense of the order of magnitude of changes in key assumptions of required tariffs and investor returns. The economic impact of changes in key assumptions are discussed in Section 3.2 Economic Rate of Return. In addition to an assessment and quantification of these risk issues, possible mitigation strategies are also discussed. A risk matrix is incorporated at the end of this section, which outlines project risk factors, their causes, possible mitigation strategies and the potential effects on lenders and equity investors. Key risk factors considered include:

- Demand
- Construction Risk
- Operating Risk
- Startup Delay
- Credit Risk
- Price Reform Risk
- Fuel Supply and Price
- Contract Enforceability
- Changes in Tax Policy
- Cost Overruns
- Performance Risk
- Exchange Rate
- Coordination Risk
- Political Risk

3.3.2 Demand

Energy demand in Russia has declined precipitously in recent years because of decreasing industrial demand. According to the Least Cost Plan, electricity consumption in the industrial sector in the Krasnodar Krai has declined 53% between 1990 and 1994. Demand is expected to level off in 1995 before growing at an estimated annual rate of 4% - 5% based on projections of future economic activity in the North Caucasus region.

The financial model was used to test the impact of a possible decline in demand on tariffs. To quantify a drop in demand, the low demand case of the ICF model was used a starting point. Although the ICF model output is used primarily for economic analysis purposes

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and not for financial risk purposes, the ICF model does yield a relative comparison of a base case and low demand case estimated output levels of incremental energy supplied byKrasnodar GRES . In Table 3.3-1 below, low demand incremental energy is shown as a percentage of base case demand. These same percentages were applied to total base case output in the financial model to quantify a low demand sensitivity case.

Table 3.3-1
Incremental Energy Estimates from the ICF Model
Low Demand as a Percentage of Base Case Demand

1998	1999	2000	2001	2002	2003	2004	2005	2006 and beyond
78.8%	66.7%	66.3%	73.4%	76.3%	79.9%	82.7%	85.8%	100.0%

As Table 3.3-2 shows, if tariff levels are allowed to increase to ensure the indicated equity returns (15% returns on Russian equity in the Base Case), then the levelized one-part tariff (net of VAT) increases from $0.0302 in the Base Case to $0.0324 in the sensitivity scenario, which represents an increase of 7%. Furthermore, in the event of lower demand, the associated decrease in revenues decreases the amount of internally-generated cash targeted for construction financing. The low demand scenario results in a shortfall of internally-generated funds of $28 million during the construction phase. This points to the potential need for additional equity infusion from the Ownership group to mitigate the potential risk of shortfalls in internally-generated cash.

Alternatively, if the tariff is not adjusted for the drop in demand, then equity returns fall from 15% to 12.9%. The two-part tariff is also shown, which indicates that, with lower demand and in order to achieve 15% equity returns, the capacity charge would need to increase from $92.00 per kW per year in the Base Case to $95.50 per kW in this scenario.

If demand growth does not respond as expected, project risks can be partially mitigated by structuring the power purchase agreement to provide for capacity and usage charges, with capacity payments providing for recovery of fixed charges. As a practical matter, the new plant is expected to be the most efficient in the region and, therefore, is least likely to be taken off-line in the event of weak demand growth. It is anticipated that the tariff of the new plant will be passed on to industrial and retail customers as a blended rate. A stand-by credit or equity facility is required to provide for any cash shortfalls in the early years of the project caused by weak demand growth.

An important advantage of combined cycle technology is the modular nature of its construction. If demand is significantly lower than expected during the early construction years, it is possible to operate the plant under partially-completed capacity and delay the remaining construction.

The risk mitigation approach will require careful coordination with procurement efforts to ensure that further equipment deliveries and payment obligations are delayed. While this mitigation option allows for a reduced the level of potentially stranded investments in the event of low demand, it results in higher operating costs, and therefore, higher required tariffs.

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Table 3.2-2
SCENARIO 1: LOW DEMAND

SCENARIO ASSUMPTIONS

Low demand forecasts for incremental energy as estimated in the ICF model were used as a relative guide for estimating low demand total output levels in quantifying the impact on tariffs. These relative ratios are shown in Table 3.3-1.

SCENARIO RESULTS

A. If tariff adjusts to maintain 15% equity returns, then:

	w/o VAT	w/ VAT
One Part Tariff		
Option 1: Average Tariff ($/kWh) ('95 US$)	$0.0324	$0.0393
Two Part Tariff		
Option 2a: Capacity Charge ($/kW/yr) ('95 US$)	$95.50	$116.03
Option 2b: Energy Charge ($/kWh) ('95 US$)	$0.0138	$0.0168

Furthermore, the low demand scenario creates a cash shortfall in years 2000 and 2001 totaling $28 million.

B. If tariff does not adjust, then Russian equity returns fall to 12.9%.

3.3.3 Construction Risk

Delays, cost overruns and quality designs present additional risk factors. Part of the approach for mitigating the risk of cost overruns is the inclusion of contingencies in the project cost estimates. These contingencies total $66 million and are included in the total projects costs. To further mitigate risk, contracts for design and implementation should be tendered in a competitive bid with international contractors invited to participate. Bid documents should be prepared to ensure that the winning bidder has both international and combined cycle experience and is technically, financially and managerially qualified to manage the project. Contracts will provide for performance bonding, completion guarantees and liquidated damages to ensure compliance with the terms of the agreement. The consultants have drafted preliminary bidding documents and it is anticipated that consultants will participate in bid evaluation.

Equipment procurement will also be managed pursuant to an international tender. To mitigate physical risks associated with transportation, handling and construction, both the contractor and equipment suppliers will be required to insure against physical damage.

3.3.4 Operating Risk

Combined cycle technology is new to Russia and, therefore, Kuban GRES has no experience operating such facilities. Quantifying this risk can be simulated with a sensitivity run of the model at a lower load factor, as was done for the Lower Demand Case (see Table 3.3-2). It is anticipated that Kuban GRES will provide primary staffing. To mitigate operating risk, it is anticipated that equipment supply contracts will include provisions for service and maintenance and will provide training for Russian staff in combined cycle operations and will continue to be available after plant startup to provide on-site support in the operation of combined-cycle technology, especially in controls and operation of gas turbines plus assistance with operation and maintenance. The participation of a foreign electric utility with combined cycle experience as part of the equity group would further enhance the operational efficiency of the plant.

3.3.5 Startup Delay

If start-up delays were encountered, the financial impact could be rather dramatic, as Table 3.3-3 illustrates. To quantify the exposure of a startup delays, a sensitivity scenario was considered in which there a one year delay in operating the gas turbine and combined cycle units. In such a scenario, the required tariff would increase from $0.0302 in the Base Case to $0.0341 in this case, an increase of 13%. Furthermore, if such startup delays did occur, then a cash shortfall of $86 million would occur in the year 2000. This points to the potential need for additional equity infusion from the Ownership group to mitigate the potential risk of shortfalls in internally-generated cash. If tariffs did not adjust, then equity returns would fall from 15% to 12.1%, a 15% drop in the internal rate of return. This sensitivity scenario assumes that capital expenditures are not adjusted if construction delays occur. In fact, cash payments would be delayed in cases where startup delays were the responsibility of the contractor.

Another risk that could lead to startup delays is the risk that members of the Russian Ownership Group are not able to make their equity contributions on time. To help mitigate this risk, the World Bank loan could include a covenant stipulating that projected equity contributions be deposited in an escrow account at least six months prior to the time the cash expenditures are anticipated. While this approach does not prevent potential liquidity or solvency risks among the Ownership Group, it does provide for an advance warning of potential problems and delays.

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Table 3.3-3
SCENARIO 2: DELAY IN STARTUP

SCENARIO ASSUMPTIONS

With capital expenditures occurring on schedule, startup of plant operations are assumed to be delayed. This scenario assumes a one year delay in startup of simple cycle and combined cycle modules.

SCENARIO RESULTS

A. If tariff adjusts to maintain 15% equity returns, then:

	w/o VAT	w/ VAT
One Part Tariff		
Option 1: Average Tariff ($/kWh) ('95 US$)	$0.0341	$0.0414
Two Part Tariff		
Option 2a: Capacity Charge ($/kW/yr) ('95 US$)	$83.75	$101.76
Option 2b: Energy Charge ($/kWh) ('95 US$)	$0.0138	$0.0168

Furthermore, the construction delay creates a cash shortfall in the year 2000 of $86 million.

B. If tariff does not adjust, then Russian equity returns fall to 12.1%.

3.3.6 Credit Risk

Russian enterprises are experiencing severe liquidity problems as a result of dislocations in the financial system. The economic downturn of the Russian economy combined with tight credit has resulted in an over-extension of intercompany borrowings and significant build-up in customer payments for electricity. The JEPAS study estimates that electricity non-payments account for approximately 50% of billings. As discussed in the Financial Analysis section of this report, efforts are being made at Kubanenergo and RAO EES Rossii to improve the customer payments problem. However, if this problem takes longer than expected to be resolved, there could be a serious financial impact on the project. A sensitivity scenario was run in which the accounts receivable is assumed to decline slowly from 180 days sales in 1995 to 45 days sales in 2005; thus taking 10 years to normalize rather than the base case assumption of normalizing within 5 years. The impact is negligible on required tariffs, but there is an increase in required startup working capital. Under the assumptions of this sensitivity scenario, an additional $18 million in working capital would be required in 1998. This risk could be mitigated by the availability of a stand-by credit or equity facility.

Kubanenergo is not financially qualified to be the primary customer of power produced by the Project. For this reason, a power purchase agreement will be executed with RAO EES

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Rossii. RAO EES Rossii will then resell power to the grid and have responsibility for cash collections. Credit exposure of the Project can be mitigated by structuring the power purchase agreement on a "take-or-pay" basis for capacity and establishing a special account under control of the Project to give priority to the Project for RAO EES Rossii collections.

Although RAO EES Rossii is currently well resourced, there is risk associated with the potential restructuring and privatization of the company. Investors' security could be diminished if RAO EES Rossii was restructured or privatized. This risk could be mitigated, ideally, through a counter-guarantee from the Russian government or by tying the transaction to specific RAO EES Rossii assets and/or cash flows.

3.3.7 Price Adjustment Risk

The newly formed Federal Energy Commission has authority over wholesale tariffs. Currently, tariffs can only be reset on a quarterly basis, and this lag typically has a negative effect on cash flows and earnings. Given the high inflationary environment in Russia, this poses a risk to the Project. This risk could be mitigated in the power purchase agreement by specifying a mechanism to account for the timing difference and requiring that a reserve fund be established by RAO. The Project could draw-down on the reserve fund in the event that conditions change driving up the operating costs of the Project before the tariff can be reset to absorb this increase. RAO EES Rossii would be required to replenish the reserve based on actual drawdowns.

The tariff required to make the Project viable on a financial basis is higher than the average tariff in the region. Spreading the price increase amongst customers is required to avoid any price shock to customers.

3.3.8 Fuel Supply

Based on the monopolistic profile of the Russian gas industry, reliable fuel supply is a risk inherent in the Project. Gazprom is expected to be the sole supplier of fuel to the Project. In the event of service interruption, it is not likely that alternative sources of supply will be available in the near-term. To mitigate this risk, the fuel supply risk should be shifted to RAO EES Rossii by providing for satisfactory payment under the power purchase agreement regardless of the availability of fuel. To further mitigate risk, the Project would enter into a long-term fuel supply agreement with Gazprom specifying quality, quantity and terms of sale. Penalties will be assessed for unavailable, late, unacceptable or insufficient supply. Gazprom's substantial commitment to the project as an equity investor would also mitigate this risk factor.

Increases in fuel costs also poses a risk, which could be mitigated through a fuel cost pass through arrangement in the tariff agreements. As an indication of the potential impact of increase gas costs, a sensitivity scenario was run in which the cost of gas increases by

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20%, from $61 to $73 per 1000 m^3. As the results indicate in Table 3.3-5, if the tariff does not adjust, then the equity returns fall from 15% in the Base Case to 11.8%. However, a mitigation strategy is incorporated into the power purchase agreement, which allows for a direct pass through of fuel price increases. As the table shows, a 20% increase in gas costs, when passed on to customers, results in an increase in the usage charge of about 20%, from $0.0138 to $0.0164 per kWh.

Table 3.3-5
SCENARIO 5: HIGHER GAS COSTS BY 20%

SCENARIO ASSUMPTIONS

	1998-2004	2005 & Beyond
Base Case	$61.00	1% increase per annum
Higher Gas Costs Case Which is an increase of 20%	$73.20	1% increase per annum

SCENARIO RESULTS

A. If tariff adjusts to maintain 15% equity returns, then:

	w/o VAT	w/ VAT
One Part Tariff		
Option 1: Average Tariff ($/kWh) ('95 US$)	$0.0325	$0.0394
Two Part Tariff		
Option 2a: Capacity Charge ($/kW/yr) ('95 US$)	$89.50	$108.74
Option 2b: Energy Charge ($/kWh) ('95 US$)	$0.0164	$0.0199

B. If tariff does not adjust, then Russian equity returns fall to 11.8%.

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3.3.9 ENFORCEABILITY

Enforceability of contracts is a risk factor, given the changing nature of the Russian legal system and unreliability of courts of competent jurisdiction to adjudicate disputes. To mitigate this risk, all contracts should specify penalties for non-performance and procedures for arbitrating disputes. To the extent feasible, specific collateral should be attached.

3.3.10 RISK ANALYSIS MATRIX

The following risk matrix, Table 3.3-6 below, is segregated to account for risk exposure during the bidding and construction period and during operation of the Project. The matrix outlines major areas of risk, their causes, possible mitigation strategies and their potential effects on debt and equity holders.

Table 3.3-6
RISK ANALYSIS MATRIX

RISK	REASON	MITIGATION STRATEGY	EFFECT ON DEBT	EFFECT ON EQUITY
DURING BIDDING AND CONSTRUCTION PERIOD				
Bids in excess of cost estimates	Change in market prices.	If revised costs result in tariff in excess of a pre-determined target, suspend/ terminate project.	No recovery of origination costs.	No recovery of development costs.
Equipment.	Damage to equipment during shipping and installation.	Contractor and vendor required to ensure on-time delivery and condition of equipment.	No effect unless equipment delays reduce cash flow.	No effect unless equipment delays reduce cash flow.
Construction of gas pipeline or transmission line delayed.	Delays by Gazprom or RAO, respectively.	Penalties assessed to participant causing delay, payable to Ownership Group.	No effect unless penalties insufficient to provide full recovery.	No effect unless penalties insufficient to provide full recovery.
Delay in start-up	Contractor negligence.	Carefully screen and prequalify bidders. Penalties assessed daily pursuant to turnkey contract.	No effect unless penalties insufficient to provide full recovery.	No effect unless penalties insufficient to provide full recovery.

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Table 3.3-6
RISK ANALYSIS MATRIX

RISK	REASON	MITIGATION STRATEGY	EFFECT ON DEBT	EFFECT ON EQUITY
Delay in start-up (continued)	Permitting and/or regulatory delays.	Contingencies and stand-by equity/credit facility.	No effect until contingencies exhausted or stand-by credits drawn. Thereafter, reduced coverage ratios.	Return reduced to the extent contingencies are insufficient.
	Force majeure.	Business interruption insurance (if available). Stand-by equity/credit facility.	Debt coverage ratios reduced after insurance exhausted.	Return reduced.
	Failure of ownership group to make timely equity contributions.	Requirement to pre-fund equity contributions. Agreement for other equity investors to fund any shortfall.	Potential to increase debt/equity ratio.	Return reduced.
Cost overrun (except finance costs)	Contractor negligence.	Carefully screen and prequalify bidders. Negotiate fixed price contract.	No effect.	No effect.
	Force majeure.	Insured event covered by business interruption insurance (if available).	No effect until insurance exhausted. Thereafter, reduced coverage ratios.	Return reduced.
	Change in law, permitting or other regulatory delay.	Stand-by credit/equity. Tariff adjustment during operation.	Coverage ratios reduced.	Return re-duced.
	Taxes and duties.	Contingencies and stand-by credit facility provide for recovery through tariff adjustment during operation.	Coverage ratios reduced.	Return reduced.

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Table 3.3-6
RISK ANALYSIS MATRIX

RISK	REASON	MITIGATION STRATEGY	EFFECT ON DEBT	EFFECT ON EQUITY
Finance cost overrun.	Change in interest rates or investor returns in excess of estimates.	If tariff exceeds predetermined target, and project has not commenced, suspend project. Contingencies or draw on stand-by equity/credit facility.	Coverage ratios reduced.	Equity requirements increase to maintain debt/equity ratio. Return reduced.
Failure of plant to meet performance specifications.	Contractor negligence resulting in capacity shortfall.	Penalties assessed pursuant to turnkey contract.	No effect unless penalties insufficient to provide full recovery or contractor credit deteriorates.	Return reduced if penalties insufficient to provide full recovery by equity investors.
	Contractor negligence resulting in unacceptable heat rate.	Penalties assessed pursuant to turnkey contract. Potential to pass increased fuel cost to customer.	No effect unless penalties insufficient to provide full recovery or contractor credit deteriorates.	No effect unless penalties insufficient to provide full recovery or contractor credit deteriorates.
Exchange rate	Total project cost increase due to change in exchange rates.	Ability to pass cost on to customers via tariff adjustment. Contingencies and stand-by equity/credit facility.	Coverage ratios reduced depending on timing and ability to pass cost increases through to power purchaser.	Return reduced if increased cost cannot be passed on to power purchaser.
Coordination	Delays in start-up resulting from poor project coordination.	Contingencies and stand-by equity/credit facility. Penalties in contracts.	No effect unless contractor penalties insufficient. Thereafter, coverage ratios reduced and credit deterioration.	Return reduced if penalties insufficient to provide full recovery.

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Table 3.3-6 RISK ANALYSIS MATRIX				
RISK	**REASON**	**MITIGATION STRATEGY**	**EFFECT ON DEBT**	**EFFECT ON EQUITY**
Coordination (Cont'd)	Sponsor related	Contingencies and stand-by equity/credit.	Coverage ratios reduced.	Return reduced.
DURING OPERATION				
Failure of demand to materialize as expected	Weak economic recovery	Design efficient plant as base load facility. PPA which provides for capacity charges to cover debt service and provide a minimum return to equity investors. Delay second module equipment and installation and operate under partial capacity	No effect if power purchaser satisfies obligations under terms of PPA.	Limits return.
Outages, shortfall in capacity or insufficient heat rate.	Operator negligence.	Equipment suppliers to provide training to Russian staff. Required maintenance reserve.	No effect unless reserves exhausted.	Return reduced if negligence occurs.
	Equipment malfunction.	Manufacturer's warranty with penalties. Insured event (if available).	No effect unless manufacturer's penalties and/or insurance insufficient to cover debt service during suspension of service.	Return reduced if manufacturer's penalties and insurance exhausted.
	Force majeure	PPA which provides for capacity charges to cover debt service and minimum return to equity investors.	No effect unless power purchaser defaults. Government guarantee in the event of default.	Return limited and reduced in event of default.

Table 3.3-6
RISK ANALYSIS MATRIX

RISK	REASON	MITIGATION STRATEGY	EFFECT ON DEBT	EFFECT ON EQUITY
Exchange rate	Increased operating cost due to exchange rate changes.	Index PPA to changes in exchange rates.	No effect.	Return reduced if indexation lags deterioration.
Political	Expropriation or breach of agreement by Russian government	Termination of project with compensation pursuant to government guarantee. Political risk insurance.	Loan prepaid or assumed by government.	Compensation paid to equity owners pursuant to any government guarantee or political risk insurance.
Credit	Increased potential for default due to RAO restructuring. Demonopolizatio n of Russian electric power sector.	Government guarantees performance. Project debt and at least some portion of equity return tied to specific RAO assets/cash flows. Debt service reserve.	Increases potential for credit deterioration.	Potential adverse impact on returns.
O&M cost overrun	Actual costs exceed estimates.	Stand-by credit/equity pending tariff adjustment.	Decreases coverage ratios.	Reduce returns.
	Force majeure	Stand-by credit or equity pending tariff adjustment.	Decreases coverage ratios.	Reduce returns.
	Change in law	Ability to pass through impact in tariff.	No effect.	No effect.
Inflation	High inflation rate.	Tariff indexed to inflation rate.	No effect.	No effect.
Currency convertibility	Unavailability of foreign exchange.	Government guarantees availability of foreign exchange.	No effect unless project is terminated. If terminated, loan is repaid.	No effect unless project is terminated. If terminated, equity investors receive compensation.
Foreign exchange	Adverse changes in exchange rates.	Tariff pegged to exchange rate.	No effect.	No effect.
Fuel price	Increase in fuel costs.	Direct pass through via tariff adjustment.	No effect.	No effect.

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Table 3.3-6
RISK ANALYSIS MATRIX

RISK	REASON	MITIGATION STRATEGY	EFFECT ON DEBT	EFFECT ON EQUITY
Fuel availability	Lack of alternative suppliers.	Three day fuel oil reserve. Daily penalties assessed to supplier. Capacity charges.	Credit deterioration.	Returns reduced.

3.4 Financial Analysis

3.4.1 Overview

The financial viability of the Project is highly dependent upon the financial capacity of the Russian Ownership Group. The following provides an overview of the current financial situation of the three primary proposed participants in the Russian Ownership Group: RAO EES Rossii, Gazprom and Kubanenergo. This overview is based on select limited financial information made available by the companies or through published information sources. Kubanenergo was cooperative, provided internal unaudited financial statements and made management available to answer questions. RAO EES Rossii provided select financial information and participated in interviews. Gazprom would not provide financial information pending further consideration of the Project. Therefore, the overview of Gazprom's financial status is limited to publicly available information. The overview is intended to provide a framework for further financial analysis of the proposed Ownership Group. A lender would require more detailed financial information on all participants prior to making a lending decision.

During the performance of this project investigation, additional potential equity participants in the Ownership Group have been identified. These include the Unified Electric Energy Complex Corporation, AO Energo Machine Building Corporation, and a foreign investor, Amoco Eurasia Petroleum Company.* No financial information for these additional participants was provided and no financial analysis has been performed. The financial capabilities of AMOCO are very strong and will enhance the ability of Kuban GRES to raise capital.

The Unified Electric Energy Complex Corporation is a for-profit association of member companies, primarily in the power sector. The company provides consulting services, power sector planning and research, lobbying and legal research, and investment advise and coordination. Capital is raised through membership fees, manufacture and sale of products and other activities.

AO Energo Machine Building Corporation is comprised of enterprises involved in developing, manufacturing and supplying power equipment for thermal, nuclear and hydro power plants. The companies also manufacture specialized equipment for other heavy industries. The combined annual product output is estimated to be $2 billion. The Corporation is expected to make cash equity contributions and to participate in the competitive tendering process for equipment supply.

*Amoco Eurasia Petroleum Company, a Delaware (USA) Corporation, is Amoco Corporation's representative office in Russia.

3.4.2 Kubanenergo

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Financial Situation

The Russian power sector is confronted with considerable structural uncertainty and is faced with a severe liquidity crisis stemming from a break-down in intercompany payments and customer collections. Deteriorating economic conditions in the country have had a material adverse effect on industry, leaving most companies without sufficient working capital or funds for investment. Increasing raw material costs combined with slow receivable collections have resulted in liquidity and profitability problems for Kubanenergo.

According to statutory requirements, Kubanenergo prepares financial statements on a quarterly basis. Financial statements prepared on a regular basis include a balance sheet and income statement. Cash flow statements are not prepared in the normal course of business. Financial statements are unaudited and diverge from international accounting standards in several important ways. The primary differences are noted as follows:

- Cash as opposed to accrual accounting.
- Inventories are not valued at the lower of cost or market (carried primarily at cost).
- Obsolete inventory is not reserved against and written-off.
- Delinquent receivables are not aged, reserved against and written-off on a regular basis.
- Estimated useful lives of assets for depreciation purposes seem to exceed actual useful lives.
- The accounting for equity accounts and in particular retained earnings does not follow international rules as fund accounting is used.
- Related entities are not consolidated.

Table 3.4-1 summarizes Kubanenergo's financial condition as of December 31, 1994 and March 31, 1995. Financial information is unaudited and was provided by Kubanenergo management. The consultants have not verified the accounts and have relied upon management's representation that the financial information accurately reflects the financial condition of Kubanenergo as of the dates indicated.

Liquidity

Due to the economic downturn and lack of adequate enforcement mechanisms, non-payment for electricity has reached nearly 50% of total billings throughout Russia according to the recently completed JEPAS study. Uncollected electricity bills amounted to 15 trillion rubles at year-end 1994 for the Russian power sector, putting severe liquidity constraints on enterprises and the sector's ability to fund capital investments. In 1994, the Russian power sector supplied electricity valued at 24.6 trillion Rubles ($12.4 billion), but received only 10.3 trillion Rubles ($5.3 billion) from customers. At year end, supplier arrearages totaled 8.2 trillion Rubles ($4.1 billion).

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Review of Kubanenergo's recent balance sheet information without further interpretation or adjustment tends to distort the true financial condition of Kubanenergo. Accounts receivable are not aged and doubtful accounts are not regularly reserved or written-off. This tends to overstate the value of receivables. In addition, receivables are not indexed for inflation which tends to distort the book carrying value of customer receivables. The balance of receivables outstanding has increased from 156 billion Rubles at year end 1994 to approximately 300 billion Rubles, or more than $65 million, by July 1995, and to approximately 322 billion Rubles, or more than $70 million, by October 1995.[1]
[10] Kubanenergo only recently initiated a policy of aging receivables. Therefore, it is not possible to estimate the recoverability of receivables with any degree of accuracy. However, as of June 1, 1995, management estimates that 58% of receivables had been outstanding greater than three months. This figure was estimated at 52% as of July 1, 1995. Furthermore, management estimates that nearly all household customers are current or nearly current in their accounts; most overdue balances reside with industrial, agricultural and government organizations.

Kubanenergo management has recently initiated a program to relieve the financial pressure on the Company caused by the non-payments problem. Major provisions of management's plan are as follows:

[10] It has not been determined if these figures include fines for overdue amounts. The question was presented to management but has not been answered. Numerous other written questions were presented to management concerning aging of accounts, largest outstanding debts and largest customers overall, comparisons over time, the extent of and policy towards doubtful debts, differentiation of receivables by sector, management's expectations regarding the effect of receivables on cash available for future investments, management's capital investments and obligations over the next five years, and the existence of off-balance sheet items (such as investments, affiliates, etc.). Responses were never received to these questions.

Table 3.4-1
Kubanenergo -- Balance Sheet

(Amounts in millions of Rubles - unaudited)	12/31/94	3/31/95
Current Assets		
Cash and cash equivalents	25,412	35,591
Accounts Receivable net	155,931	218,296
Inventories	19,377	28,516
Advances	13,247	11,831
Other current assets	15,254	12,047
Losses	0	3089
Total Current Assets	**229,222**	**306,281**
Long-term Assets		
Property, Plant and Equipment	2,602,915	2,614,494
Less Accumulated Depreciation	(1,365,303)	(1,384,290)
Net Property, Plant and Equipment	1,237,612	1,230,204
Long-term financial investments	266.00	567.00
Capital work-in-progress	337,081	345,203
Net Long-term Assets	**1,574,959**	**1,575,974**
Total Assets	**1,804,181**	**1,882,255**
Current Liabilities		
Short-term loans	28,735	32,210
Accounts payable	168,396	236,359
Advances / Deposits from customers	39	35
Other current liabilities	0	128
Total Current Liabilities	**197,171**	**268,732**
Capital, Reserves, and Long-term Debt		
Long-Term Debt	215.00	209.00
Founders Capital	1,191	1,191
Reserves	66,874	69,532
Retained Earnings	1,538,730	1,542,591
Total Capitalization	**1,607,010**	**1,613,524**
Total Liabilities and Stockholders' Equity	**1,804,181**	**1,882,255**

1 Introduction of a receivables aging system which will enable management to distinguish receivables outstanding for less than or greater than three months.

2. Introduction of a two part payment scheme for industrial customers whereby a base fee is assessed for the availability of electricity and a usage charge is levied for each kilowatt hour consumed. The base fee is due and payable the 1st of each month and the usage charge is due and payable by the 10th of each month based on average historic use. As a result Kubanenergo is able to receive as certain amount of up-front payment for services for commercial customers.

3. Kubanenergo diverts cash in bank accounts of customers whose accounts are in arrears to Kubanenergo's account wherever possible.

4. Bad debts are written-off after 3 years.

5. Service to industrial and commercial customers with outstanding balances is terminated during periods of peak demand.

6. A policy, whereby retail customers are required to pay charges by the 10th of each month or be assessed a late charge equal to 1% of the outstanding balance per day. Receivables due from individual households are not included in the balance sheet. Individual households have an incentive to pay on time as all electricity is due at the current rate which is increased regularly due to inflation. Payments are made directly at banks or payment stations where individuals pay for amounts as read off by them on their meters so that no amounts are handled by the company itself.

These combined actions do not seem to be sufficient to resolve the non-payments problem. Kubanenergo is at liberty to terminate service to many industrial and commercial customers for non-payment of electricity bills. However, government decree prohibits termination of service to certain key sectors, which includes railways and agriculture, two of Kubanenergo's largest sectoral customers. Management believes Kubanenergo's high exposure to the agricultural sector, which has experienced significant financial deterioration, will continue to burden the Company.

Short-term assets must be evaluated relative to short-term liabilities. As of July 25, 1995, short-term debt had risen to 50 billion Rubles from 32 billion Rubles as of June 30, 1995. Accounts payable totaled 236 billion Rubles as of June 30, 1995. Of the outstanding balance of payables, approximately 35 billion Rubles were due to Gazprom and 155 billion Rubles to RAO EES Rossii.

Fixed Assets and Capital Investment

Fixed assets are carried on the books at cost and periodically revalued to reflect the impact of inflation. Revaluations are based on government prescribed revaluation factors, which

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may not reflect the true economic devaluation for the various assets of individual companies. Over the past few years, fixed assets were revalued in July 1992, January 1994 and January 1995. The average revaluation factors applied to fixed assets accounts at these dates were 28.6, 22.6 and 3.5, respectively.

With regard to fixed assets, standard depreciation schedules exist and are followed by the company. However, management indicated that property, plant and equipment includes certain assets recorded on the books at depreciated cost which have no value but cannot be written off until the end of the depreciable life. Management was unable to present details of such assets. Annual depreciation varies between 1.2% to 6.0% of the original cost of the asset and is reset periodically consistent with the revaluation factors of applied to fixed assets. With regard to low value items, 50% is written off in the year of purchase, 50% in the last year of the expected life. In general, it seems that depreciable lives overstate economic usefulness. In this respect, the book value of fixed assets tends to overstate true economic value.

Future capital expenditures required to maintain the existing asset base are unclear. Such investments required to maintain the current asset base are important since it provides an indication of the Company's ability to fund new projects. The head accountant of Kubanenergo estimates that 25 billion Rubles are needed per annum to sustain the current asset base. Management indicated that the Company is not pursuing any other large capital projects other than the Project.[11]

Kubanenergo anticipates in-kind contributions of land, improvements as well as certain tax payments already made as part of its capital contribution to the Project.[12] Management informed us that land which will be contributed to the Project was acquired for approximately 12 billion Rubles and the associated taxes are also about 12 billion Rubles. Through the end of 1994, approximately 15 billion Rubles had been expended to development the site. The Ownership Group has not yet been formed and, therefore, final resolution of the acceptability of in-kind contributions to the Project has not been determined. Kubanenergo has not established its ability to fund cash capital contributions. However, given the liquidity issues faced by the Company, and lack of availability of long-term capital in the Russian economy, it is highly unlikely that Kubanenergo has the capacity to fund a major portion of the total equity requirements of the Project.

Capitalization

Historically, investment in the power sector was funded through internally generated funds and allocations from the state budget. As a result, Kubanenergo has a low debt/equity

[11] Specific written questions regarding other capital projects, investments and obligations, which were submitted to management, never received a reply. While management stated they were not pursuing other major capital projects, there is a current program to replace 159 MW of aging boiler equipment and 190 MW of combustion turbines at the Krasnodar TETS site with a 400 MO CHP/combined cycle plant.

[12] It is not clear if the in-kind land donation to which Kubanenergo has referred is the same real estate that the Mostovskoy District Administration is contributing to the project, as described in section 4.1.1.4.

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ratio with most capital of the company represented by retained earnings, reserves and shareholder equity. Fifty-one percent of the shares of Kubanenergo are held by employees of Kubanenergo with the balance (49%) owned by RAO EES Rossii. Shares were sold to employees for 1,700 Rubles per share. A secondary offering is possible, but at this point management believes it is unlikely that the Company could raise additional capital through this mechanism.

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Normally a low debt/equity ratio indicates financial capacity to borrow to fund future investment. However, given the lack of liquidity in the Russian financial system, the availability of third party debt financing to the Company is highly unlikely. In addition, long-term credits are not available and short-term financing is only available at high rates.

Profitability of Company

Table 3.4-2 summarizes Kubanenergo's financial performance for the quarter ended March 31, 1995 and the eleven months ending December 31, 1994. Statements for the full year 1994 were not available. Prior period comparisons are difficult given the cash basis of accounting practiced by the Company and high rate of inflation.

Table 3.4-2
Kubanenergo -- Summary Income Statement

(Amounts in thousands of Rubles - unaudited)	**11 months ended 12/31/94**	**Quarter ended 3/31/95**
Gross Revenues	15,673,5271	269,128,996
Less VAT and special tax	(25,897,793)	(50,000,722)
Net Revenue	130,837,478	219,128,274
Costs of Goods sold	(108,654,477)	(193,452,661)
Gross Profit	22,183,001	25,675,613
Other Expense, net	1,303,060	(5,041,799)
Pre-tax Income	23,486,061	20,633,814
Taxes	(7,236,986)	(12,369,215)
Net Income	16,249,075	8,264,599
Distribution to Accumulation Fund	(8,934,155)	(3,529,554)
Distribution to Consumption Fund	(5,130,553)	(4,283,096)
Distribution for Charitable Purposes	(1,900,414)	(104,867)
Other Distributions	0	(3,435,979)
Total profit (loss)	**0**	**(3,088,897)**

Kubanenergo recognizes revenue on a cash rather than an accrual basis. A sale is only accounted for when payment is received. Combined with the non-payments problems experienced by the Company, it is not possible, therefore, to develop an accurate picture of current period revenue or profitability. VAT of 20% is withheld by the company on all goods sold and netted with VAT paid on goods purchased.

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Significant tax assessed to the Company includes income tax which has averaged approximately 35% of pre-tax profit and excess salaries tax. Excess salaries tax is payable on salaries in excess of 262,320 Rubles per month.

According to management, losses incurred in the first quarter will probably not be recovered in the rest of the year. Management argues that the reason for the current profitability problem lies in the fact that gas prices have risen considerably while the electricity tariff has not risen sufficiently to cover these increased costs. In addition, account receivables collection represents a major problem to the Company. Management foresees that because of current situation, future earnings will have to be placed into the social fund and will thus not be available for investments. Such a policy does not seem to be consistent with that of an equity investor as it suggests serious potential implications on the sustainability of investments commitments.

3.4.3 RAO EES Rossii

<u>Conclusion</u>

RAO EES Rossii is one of the largest utilities in the world based on installed capacity. Although the company has been affected severely by the ongoing non-payment crises as described above, we have no doubt that the company is financially capable of participating in the envisioned project. However, the Krasnodar Krai project competes with various other projects that the company may or may not want to participate in. The ownership group will thus need to ensure RAO's commitment to the project.

Table 3.4-3 summarizes RAO EES Rossii's financial condition as of December 31, 1994 and June 30, 1995.

At June 30, 1995 current assets exceeded current liabilities by approximately $616 million. However, 95% of the current assets are represented by accounts receivable. RAO EES Rossii was severely affected by the non-payment crisis as described above. However, management informed that various steps were undertaken to alleviate the problem and that these steps had been successful although no written documentation was provided to the consultants. Management indicated that payment experience improved in June 1995 but did not provide financial documentation to support this contention. Steps undertaken included:

1. Set-up of a delegation visiting producers and consumer throughout Russia in the third quarter of 1994.
2. Enacting late penalties of 0.5% per day.
3. Set-up of a permanent management group focusing on accounts receivable with updated computer data analysis capabilities.
4. Terminating service to high profile delinquent accounts such as the foreign ministry to illustrate the problem.

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Table 3.4-4 summarizes RAO EES Rossii's financial performance for the six months ended June 30, 1995 as well as the twelve months ended December 31, 1994.

Of the asset labeled "Long-term financial investments" in Table 3.4-3, the following items, as of June 30, 1995, are included:[13]

	Million Rubles
• Subsidiary energy companies	8,868,679
• Independent energy companies	8,568,269
• Other enterprises	9,075
• Joint construction activities for energy companies and other purposes	1,324,739
• Charter capital in other enterprises	61,572
• Long-term debt provided	4
• Total Long-Term Financial Investments	18,832,337

Of the item labeled "Other Distributions" of profits in Table 3.4-4, the following profit distributions are included:

	Thousand Rubles
• Moscow profit tax for construction of fiber optic cables	5,006,250
• Portion of VAT and special taxes allocated for transportation and other social purposes	9,227,219
• Penalties for late payment of taxes	6,765,000
• Expenses associated with sales of securities	1,527,925
• Total Other Distributions	22,526,394

[13] The question was posed to management in writing -- What assets and activities are represented in the financial statements? Specifically, does these financial reports concern just the transmission activities, or do they also incorporate the financial results of the Energos and generation companies in which RAO ESS Rossii is a minority or majority owner. The question was not directly answered; instead, the above breakout of long-term financial investments was supplied.

Table 3.4-3
RAO EES Rossii - Balance Sheet

(Amounts in millions of Rubles - unaudited)	**12/31/94**	**6/30/95**
Current Assets		
Cash and cash equivalents	72,190	166,896
Accounts Receivable net	4,711,152	5,604,022
Inventories	8,421	11,012
Advances	16,536	26,714
Otl :r current assets	2,893	65,341
Losses	0	0
Total Current Assets	**4,811,192**	**5,873,985**
Long-term Assets		
Property, Plant and Equipment	4,522,026	16,001,226
Less Accumulated Depreciation	(2,073,484)	(6,793,190)
Net Property, Plant and Equipment	2,448,542	9,208,036
Long-term financial investments	1,940,473	18,832,337
Capital work-in-progress	841,966	3,168,692
Other fixed assets	1,203,932	5,063,554
Net Long-term Assets	**6,434,913**	**36,272,619**
Total Assets	**11,246,105**	**42,146,603**
Current Liabilities		
Short-term loans	0	5,004
Accounts payable	2,942,079	2,851,549
Advances / Deposits from customers	301	2,616
Other current liabilities	1	239,091
Total Current Liabilities	**2,942,382**	**3,098,260**
Capital, Reserves, and Long-term Debt		
Long-Term Debt	0	0
Founders Capital	69,995	69,995
Reserves	2,105,532	3,338,772
Retained Earnings	6,128,196	35,639,576
Total Capitalization	**8,303,723**	**39,048,343**
Total Liabilities and Stockholders' Equity	**11,246,105**	**42,146,603**

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Table 3.4-4
RAO EES Rossii -- Summary Income Statement

(in Rubles)	12 months ended 12/31/94	6 months ended 6/30/95
Gross Revenues	5,484,620,327	2,163,251,301
Less VAT and special tax	(1,006,255,684)	(397,680,713)
Net Revenue	4,478,364,643	1,765,570,588
Costs of Goods sold	(4,106,366,825)	(1,548,894,954)
G oss Profit	371,997,818	216,675,634
Other Expense, net	(75,030,900)	(25,931,687)
Pre-tax Income	447028718	190743947.00
Taxes	(149,791,208)	(59,085,504)
Net Income	297,237,510	131,658,443
Distribution to Accumulation Fund	(85,668,058)	(64,198,169)
Distribution to Consumption Fund	(190,000,000)	(44,933,880)
Distribution for Charitable Purposes	(70,000)	0
Other Distributions	(21,499,452)	(22,526,394)
Total profit (loss)	**0**	0

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Capital Expenditures

Management provided the schedule in Table 3.4-5 summarizing anticipated capital projects over the next ten years.

Table 3.4-5
RAO EES Rossii -- Planned Capital Expenditures

Year	Hydroelectric Power Plants (in millions of $)	Thermal Power Plants (in millions of $)	Total (in millions of $)
1995	$1,093	$770	$1,863
1996	1,534	789	2.323
1997	1,531	791	2,322
1998	2,188	712	2,900
1999	2,510	612	3,120
2000	2,838	445	3,283
2001	2,863	303	3,166
2002	2,861	185	3.046
2003	3,006	209	3,215
2004	2,746	226	2,972
2005	2,,782	250	3,032

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3.4.4 Gazprom

Gazprom did not provide the consultants with financial information. Therefore, the following unaudited financial statements were derived from publicly available information sources. The consultants did not have the opportunity to interview Gazprom management regarding the financial condition of the Company. Table 3.4-6 summarizes the financial position of the company at December 31, 1993 and December 31, 1994.

Table 3.4-6
Gazprom -- Balance Sheet

(Amounts in billions of Rubles - unaudited)	12/31/94	12/31/93
Current Assets		
Cash and cash equivalents	2,683	1,241
Accounts Receivable net	37,480	5,124
Inventories	7,453	1,165
Advances	1,817	550
Other current assets	45,855	471
Total Current Assets	**95,288**	**8,551**
Long-term Assets		
Net Property, Plant and Equipment	41,230	40,061
Long-term financial investments	1,631	318
Capital work-in-progress	10,508	6,848
Other fixed assets	417	235
Net Long-term Assets	**53,786**	**47,462**
Total Assets	**149,074**	**56,013**
Current Liabilities		
Short-term loans	522	144
Accounts payable	32,422	4,009
Advances / Deposits from customers	251	58
Other current liabilities	7,673	1,101
Total Current Liabilities	**40,868**	**5,312**
Capital, Reserves, and Long-term Debt		
Long-Term Debt	2,239	25
Founders Capital	237	237
Reserves and Retained Earnings	107,969	50,464
Total Capitalization	**110,445**	**50,726**
Total Liabilities and Stockholders' Equity	**149,074**	**56,013**

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4.0 INSTITUTIONAL, CORPORATE AND COMMERCIAL ASPECTS

4.1 Project Structure

4.1.1 Roles of Participants in Kuban GRES

The Krasnodar GRES project has been in planning for many years. Its location in the Mostovskoy village of Krasnodar Krai had been chosen by utility sector planners based on numerous factors, including the project's significant role in the North Caucasus electric grid as a whole. The site selection has been reconfirmed by the Least Cost Investment Plan summarized in Chapter 1. Upon the restructuring of the Russian power sector, implementation of the project became the joint responsibility of RAO EES Rossii and KubanEnergo. Given limitations in available financing, both RAO and KubanEnergo have agreed to include additional equity participants in the project.

Much of the development to date has been carried out by RAO and KubanEnergo. Several studies have been prepared and the site and project infrastructure preparation has been initiated with the erection of certain project-related facilities. An enlarged owners group, Kuban GRES has emerged as potential founding shareholders through this development work. Kuban GRES consists of the following organizations, with a preliminary distribution of shares for two options (with and without foreign investment) as indicated below:

	Option1	Option 2
• RAO EES Rossii	34-37%	28%
• AO KubanEnergo	18-20%	14%
• RAO Gasprom	25%	20%
• Unified Electric Energy Complex Corporation	10%	8%
• AO Energo Machine-Building Corporation	8-10%	8%
• Potential Foreign Investor (AMOCO)	0%	20-22%

Formal agreements for participation in the project are not in place yet, and the respective equity contributions of each member have not been finalized. This owners group could also expand to include a foreign equity participant as well as other potential Russian investors, with a corresponding readjustment in the distribution of shares identified above.

The primary project owners are expected to be RAO EES Rossii, RAO Gasprom, and a potential foreign investor AMOCO based on their ability to contribute sizable portions of the required investment, as discussed in Chapter 3. Although the preliminary distribution of shares presented above also indicates a primary role for KubanEnergo as equity investor, the credit analysis presented in Chapter 3 casts significant doubt on the utility's ability to make sizable contributions towards equity. KubanEnergo's ability to make contributions to the project will depend on revenues collected through the investment component of its tariffs (See Section 4.5)

The following is a profile and summary of the roles and contributions of the major project participants.

4.1.1.1 RAO EES Rossii

RAO EES Rossii was created as a joint-stock company in 1992. RAO was given the responsibility of assuring the stability of electrical supply throughout the Russian Federation. The central dispatch center along with seven regional dispatch centers were put under RAO's control to monitor the demand/supply situation, dispatch the larger generation plants directly, and facilitate bulk power trades among utilities. Within the Unified Power System transmission facilities of 220 kv and above are under RAO's control along with existing generation facilities with 1000 MW and above for thermal stations and 300 MW and above hydro stations. In addition, the local and regional utilities (called AO-energos) were made independent joint stock companies forming part of the wholesale market for power. RAO controls 49% or more of their shares . Furthermore, a host of design institutes and construction companies are also entrusted to RAO's oversight. As a result, RAO currently has controling ownership of power facilities with total capacity of 173,000 MW as independent generation subsidiaries (independent power plants and regional utilities) forming part of the national wholesale market for power.

RAO has been actively pursuing the development of the Project at Mostovskoy since its inception and therefore, it is befitting that RAO plays a role of major shareholder in the Project. In this capacity, RAO will have appropriate representation on the Board of Directors of Kuban GRES, thereby assuring that from dispatch aspects and from the aspects of integration of the plant in the electrical network, the interests of the Project will be safeguarded. RAO's participation will also provide management of Kuban GRES with appropriate guidance in the on-going restructuring process in the electric sector.

RAO's equity contribution to the project can consist of its share of investments in developing the project to date (See Section 4.1.1.7), and future cash contributions towards equity. In addition to its role as a key investor, RAO can also assume the role of power purchaser in this project. Due to the asset base of the company, RAO would be a reliable and creditworthy candidate for the purchase of capacity and power output from Kuban GRES. As the Federal Energy Commission (FEC) would be responsible for setting and adjusting tariffs for Kuban GRES, any perception of "self-dealing" by RAO would be avoided. This would be further reinforced by the current organizational segregation of investment, generation and dispatch operations within RAO, thereby ensuring that dispatch is performed on the basis of economic and environmental rather than ownership considerations.

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4.1.1.2 KubanEnergo

AO (joint stock company) KubanEnergo is the main electric utility serving the Krasnodar administrative region (Krai) in addition to numerous municipal utilities which serve most residential customers directly. It is the only integrated generation, transmission and distribution utility in the Krai, which has approximately 1 million residential customers. KubanEnergo serves residential customers directly in the town of Sochi and all rural areas. KubanEnergo also directly serves 10,050 non-residential consumers in Krasnodar Krai. Section 4.4 provides a more in-depth overview of KubanEnergo's profile and operations.

KubanEnergo's generation base currently consists primarily of the 950 MW Krasnodar Combined Heat and Power Plant (CHP) which provides base-loaded power to the grid and heat to the city of Krasnodar and industrial facilities nearby. KubanEnergo is a deficit utility and purchases approximately half of its electricity needs from the wholesale market (RAO). In winter peak periods, significant power shortages contribute to frequent "brown-outs" and supply interruptions to large industrials. The Krasnodar GRES Project had been conceived to primarily address the power needs of KubanEnergo and Krasnodar Krai. As a result, KubanEnergo has until to date been the main sponsor of the project and taken the lead in developing the project, in close cooperation with RAO. As a result of this involvement and considerable effort and resources invested to date, and given the project's primary function to serve the region's needs, KubanEnergo is committed to playing a significant role as a founding shareholder of the project. KubanEnergo's participation as a shareholder of Kuban GRES would also help ensure an alignment of interests and cooperation among the project's stakeholders.

KubanEnergo's equity contributions will consist of capital expenditures made to date for facilities that will be transferred to Kuban GRES (See Section 4.1.1.7), and additional cash contributions toward equity. As analyzed in Chapter 3, these additional contributions will be relatively limited given the utility's current financial limitations. Nevertheless, KubanEnergo may increase its share of equity participation over time, as the payments situation of the utility is redressed and collections for the investment fund resume (See Section 4.5), through arrangements with other members of the owners group.

As discussed in Section 4.1.2, Krasnodar GRES is now planned to be incorporated into the wholesale market for power. As a result, KubanEnergo would not be the direct purchaser of power from the plant. However, as the primary consumer of power from the wholesale market for electricity generated by Krasnodar GRES, the utility's regulatory and operating characteristics have been analyzed in this chapter to ensure its reliability as a buyer of the power from the wholesale market.

4.1.1.3 RAO Gasprom

RAO Gasprom emerged as a relatively autonomous joint stock company from the USSR Ministry of Energy gas operations. It is currently an integrated nationwide natural gas exploration, production, storage, transportation, and distribution utility. Due to its direct or indirect ownership and control of most gas reserves and distribution infrastructure in the country, as well as significant foreign currency earnings through gas exports to Europe, Gasprom has become a dominant entity in the Russian energy sector. Gasprom is not regulated by an independent regulatory entity, and functions under high level government oversight due to its strategic signficance in the national energy sector and economy as a whole.

RAO Gasprom is 40% owned by the Russian Government, with the remainder of shares distributed to employees of the company and residents in key Gasprom operation areas. The company has 367,000 employees. Western sources estimate the company's revenues to have ranged from $20 billion to $27 billion in 1995, with profits of $6 billion in the same year.

Natural gas is distributed within the Krasnodar region by Kuban Gasprom, a wholly owned operating subsidiary of RAO Gasprom. Most gas in the North Caucasus region is supplied from Gasprom reserves in other parts of the country, primarily in Siberia. Therefore, from the perspective of assurances for uninterrupted availability of fuel supply to Kuban GRES, RAO Gasprom should be designated as the fuel supplier of the project. As a result, the fuel supply agreement outline presented in Section 4.3 represents a contract to be executed between Kuban GRES and RAO Gasprom directly.

In addition to its role as primary fuel supplier, RAO Gasprom is planned to have a role in the Kuban GRES project as a minority shareholder. This would ensure the participation of a financially reliable equity contributor, and enhance the project company's ability to raise equity financing and cover initial development costs. Furthermore, during the operation of the project, Gasprom's participation in the owners group would also contribute to the safeguarding of the project's interests from a fuel supply perspective, lead to cooperative fuel use planning and management, and ensure timely and amicable resolution of disputes that may arise in this area.

4.1.1.4 Amoco Corporation

Amoco Corporation, through its representative office in Russia, Amoco Eurasia Petroleum Company, is currently in discussions with the existing shareholders group to become one of the equity partners in Kuban GRES. It is expected that its participation in the project will both enhance Kuban GRES' ability to raise the equity capital required, and provide additional resources and experience in ensuring the successful development of the project.

4.1.1.5 Unified Electric Energy Complex Corporation

Unified Electric Energy Complex Corp. is a for-profit association of companies founded in 1994. Member companies primarily include power sector organizations. The company raises revenues through membership fees, manufacture and sale of products, provision of design and advisory services, and other activities. The company's stated core activities include power-sector consulting services, including sector planning, research and

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development, lobbying and legal assistance, and investment advisory and coordination. The Corporation has also raised revenues through the arrangement of barter and other transaction, both within and outside the power sector.

The company also plans the development of a capital fund for purposes of investments in power projects, provision of loan capital to member companies, and involvement in other commercial transactions. The company has been proposed as part of the founding shareholders group for the Krasnodar GRES project.

The Corporation's balance sheet for 1995, its first full year of operation, was not available as of completion of this study. A discussion with a representative of the Corporation indicated that it did not currently have cash resources available for contribution as equity to the project, and it expected to acquire an equity position in Kuban GRES through in-kind contributions of services. The World Bank, in its February mission to Moscow expressed doubts regarding the Corporation's ability to become a founding shareholder of the project.

4.1.1.6 AO Energo Machine-Building Corporation

AO Energo Machine-Building Corporation is a public joint stock company that is composed of enterprises and organizations that are involved in developing, manufacturing and supplying power equipment for thermal, nuclear and hydro power plants. The Corporation can deliver entire power complexes on a turnkey basis, with responsibility for manufacturing, installation and servicing of power equipment throughout the electric and thermal power generation process. The Corporation's members also manufacture specialized equipment for metallurgic, mining, ship-building, gas, oil refining, chemical, machine building, agriculatural, and defense sectors.

The corporation's member organizations are capable of commissioning an estimated 5000 MW per year. Their combined annual product output is estimated to be approximately $2 billion, exporting 25% of total product output. The following independent joint stock companies, which previously belonged to the Ministry of Power Machine Building, now form part of AO Energo Machine-Building Corporation:

- Electrosila, a joint stock company manufacturing hydrogenerators, turbine-generators, DC and AC power equipment, and low voltage electric devices. The company employs 9,500 personnel, and annual production has been valued at $240 million.

- LMZ (Leningradsky metallichesky zavod), a joint stock company manufacturing steam, hydro-electric and gas turbines. The company employs 10,000 people, and has annual sales equivalent to $300 million.

- Podolsky machine building factory, a joint stock company which manufactures steam boilers for 200-800 MW power units used at thermal power plants, HRSG's for combined cycle units ranging from 16 to 800 MW, reactors and equipment for nuclear power plants, and equipment for gas and oil processing and chemical enterprises. The company employs 800 persons, and has annual output of an estimated $120 million.

- Belgorodsky power machine building factory, a joint stock company producing boilers, HRSG's, and specialized pipes for thermal and nuclear plants. It has 11,000 employees and annual output of around $250 million.

- Sibirenergomash, a company manufacturing large steam and water boilers, reinforced steel for power plants, and deaerators. It has 6,000 employees and annual sales of $45 million.

- Uralelectrotyazhmash, manufacturing high voltage devices (110-1150 kV oil and air switches), electrical machines (hydrogenerators having capacity of up to 600 MW), transformers (with voltage of 6-110 kV, 80,000 kVA), semiconductor transducers and consumer goods. The company employs 7,000 people and has an estimated annual output of $200 million.

- Uralgidromash, which manufactures various types of pumps and valves. The company has 2000 employees and sales of around $15 million.

- The joint stock company "Factory for Turbine Blades", which is the only enterprise in Russia which specializes in the manufacturing of blades for steam and gas turbines. The company has 1,800 employees. The value of the company's fixed assets are estimated at $100 million.

- Chekhovsky power machine building factory, which manufactures high pressure reinforced steel piping for thermal and nuclear power plants, and oil, gas and chemical sectors. The company has 3,700 employees with annual production valued at $40 million.

The Corporation has expressed interest in participating as a founding shareholder in the project. It is expected to make cash contributions towards equity. However, as the company may also participate in the open and competitive tendering process for part of Krasnodar GRES's equipment, in the event that it is awarded such a contract, the company may trade cash payments under the contract for equity shares in the project. This approach would ensure that all contributions by the company are properly valuated under World Bank guidelines.

4.1.1.7 Development Costs Incurred To Date

Both RAO EES and KubanEnergo have expended significant resources to date in developing infrastructure at the Mostovskoy site. Total expenditures since 1993 are estimated at 70,850 million Rubles for RAO, and 30,000 Rubles for KubanEnergo.

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Although RAO's significant contributions to development efforts to date have included relocation and maintenance of a labor force at the site, development of associated social infrastructure and development of construction-related facilities, those facilities and tangible assets (both production related and social) that were contributed by RAO and KubanEnergo, and will actually be used in the construction and development of the plant would be considered as contributions to Kuban GRES.

A preliminary estimate of pre-development expenditures made by RAO and Kuban GRES in development of the Krasnodar Project has valued total costs at approximately $30.5 million. As part of these estimates, the value of only those tangible assets that could be transfered to Kuban GRES as equity contributions is as follows:

• Use of Land, Displacement of Crops	$2.5 M
• Substation, Connection to Grid, Distribution System	$1.0 M
• Telecommunications Infrastructure	$0.5 M
• Permanent Housing for 190 Families	$3.0 M
• River Bank Protection, Water Intake, Sanitary Facilities, Land Clearing, etc.	$1.0 M
TOTAL	$8.0 M

As these expenditures were incurred in Rubles over a period of several years, it may be difficult to estimate the current value in hard currency of these figures. Therefore, it is recommended that the Owners Group appoint an independent committee to finalize an inventory of assets to be transfered, and determine the value of assets to be transfered as equity contributions to the project. This would be based on an asessment of the cost of replacing the facilities, taking into account actual expenses and time delays, and a conversion to dollars at exchange rates prevailing at the time of each expenditure.

4.1.2 Identification of Power Purchaser

The owners group and the primary project sponsors have agreed to form a special purpose company, Kuban GRES (see corporate plan in Section 4.2), to implement the Krasnodar Project on a project-finance basis. As a result, the project needs to be structured as an independently viable project, financed on the basis of the strengths of its sales contracts and overall project risk profile. Therefore, the project's risk profile and financeability will be determined primarily based on the reliability of its Power Purchase Contract and the creditworthiness of the purchaser.

Kuban GRES will enter into a power purchase agreement with a single reliable entity that can assume responsibility for the purchase of capacity and power from the plant, and for resale or distribution to meet regional needs. To meet financing requirements and mitigate risks, the power purchaser would need to demonstrate its ability to absorb (utilize or resell) the products of the plant, and its creditworthiness to backstop the purchase agreements. Within this context, two major purchaser options were identified and analyzed:

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A) Option 1: KubanEnergo as Purchaser

Given its location in Krasnodar Krai, and it purpose to primarily serve the needs of the Krasnodar region, the Krasnodar Project was originally intended to sell power to KubanEnergo. However, KubanEnergo's asset base appears to be limited in supporting development of a project as large as Krasnodar GRES on a project-finance basis. This option, therefore, may be viable for a smaller project, such as a 50-100 MW plant, but would not provide a feasible alternative for Krasnodar GRES. KubanEnergo's asset value and financial capabilities, as analyzed in Section 3, are not sufficient to provide long term asssurances of payments and financial reliability to the project company. As a result, Krasnodar GRES's sales, given the project's size and required capital, would need to be back-stopped by a financially viable entity that has a significantly larger asset base than the project company's.

B) Option 2: RAO as Purchaser

Given KubanEnergo's limited resources to provide appropriate guarantees to the project company, the most viable alternative from the project company's power sales perspective would be to establish a long term power supply agreement with RAO EES Rossii as manager of the Russian wholesale market. If RAO per se is not allowed to directly enter into a power purchase agreement with Kuban GRES, then its subsidiary, the Central Dispatch Agency could be the signatory to the agreement, with appropriate guarantees by RAO for full and timely payment of power sold to through the wholesale market. RAO's current holdings in generation and transmission assets are of an appropriate size to provide the necessary guarantees to the project to make it financeable. In addition, this approach may provide an opportunity to minimize the impact on the wholesale cost of power to KubanEnergo (approximately 2.3 US cents/kWh in 4th quarter 1995) of inevitably higher tariffs from Kuban GRES (approximately 3.7-4 US Cents/KWh levelized and with VAT, at busbar plus cost of transmission and distribution) through "blending" of the tariff from the new plant with a larger generation base. Various alternatives for "blending" are discussed further in section 4.1.4.

Based on the approach outlined above, there is broad consensus among the project sponsors and regulators to incorporate Krasnodar GRES into the wholesale market through the execution of a long term power purchase agreement between the project company and RAO. As a result, RAO, as manager of the wholesale market, would have the responsibility for the dispatch of Krasnodar GRES and other large plants in the North Caucasus region to most efficiently meet the needs of deficit utilities. In this capacity, RAO would also have responsibility for enforcement of payments and collection of revenues from these consumers thereby mitigating non-payments risks for Kuban GRES.

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4.1.3 Accommodating the Project in a Competitive Power Market

To the extent that Kuban GRES will become a participant in the wholesale market, its ultimate project structure should serve two objectives from the perspective of sector development. First, the envisioned Kuban GRES structure should support and be consistent with the proposed evolution and restructuring of the sector, and meet requirements of marginal cost-based competition with other plants in the wholesale market. Second, Kuban GRES should serve as a precedent and model for future investment projects in the Russian power sector, both in enhancing investor confidence and establishing an accepted project development process in the country.

Based on current proposals to transform the power sector into a competitive market of independent generators selling to one or a multiple of power pools, the Krasnodar GRES project must be competitive with other plants to be viable. Although this approach, if implemented correctly, would inevitably lead to a more efficient power sector, it raises two key issues that need to be addressed. First, from a competition perspective, any new project would be at a disadvantage vis a vis other existing plants no matter how efficient the new plant may be. This is because existing plants have a relatively much lower burden of capital costs, debt service and depreciation. Second, as general investor confidence is relatively low at this stage of the sector's development, investment in Krasnodar GRES and other plants will be more difficult to materialize if minimum returns on investment are not assured and determined on the basis of a highly competitive environment. Therefore, the project structure for Krasnodar GRES and other similar new projects should provide incentives for efficient operation through competition, while providing the necessary assurances that the project will be able to cover such fixed costs as debt service and certain return on equity if maintained and operated well.

One possible solution to balance investor needs with the necessity to move the sector towards greater competition is to allow new projects to compete with existing ones solely on the basis of their variable marginal costs. Under this scenario, new plants would receive capacity payments for availability to allow for the ability to meet fixed capital costs and debt service, and a certain minimum rate of return. They would compete with other plants on the basis of their variable energy charge. The energy charge component (plant's marginal cost) would allow for additional profits to the project and thus provide incentives for maximum efficiency through marginal cost based dispatch. This approach would ensure efficiency without discouraging investments in new plants. If operated efficiently, therefore, Krasnodar GRES would have the opportunity to significantly enhance earnings because of its efficiency advantages and marginal cost-based competitiveness compared to existing older plants. The tariff structure proposed in the following section is based on this approach.

4.1.4 Project Structure

4.1.4.1 Overview of Project Structure

The Krasnodar GRES Project, in the form of Kuban GRES limited liability company, will be structured as an independent power producer. Therefore the company will be financed on the basis of its revenue potential and risk profile, and not those of its shareholders. The equity participants in the Krasnodar project would be shareholders in the new project company in accordance with their contributions to the project.

All debt financing raised for the project will the liability of the project company itself. For example, commercial loans and other debt financing obtained will be backed by the project company. The World Bank loan, however, will consist of a loan channeled through the Russian government to the project company, and guarantees for repayment of the loan would be provided to the World Bank by both the project and the Government. Under a separate agreement, the Implementation Agreement (IA), the project company would in turn provide assurances to the Government for the repayment of this loan. The IA, an agreement to be signed and executed between the project company, would also include assurances provided by the government to the project regarding regulatory oversight and non-interference. Principles of the IA are identified in Section 4.3.

The project company will enter into the following agreements which are described in more detail in Section 4.3:

- Construction agreements between the project company and architect/engineering firms and other contractors selected through international competitive bidding for the design and erection of the Krasnodar plant,

- Long term power purchase agreement between the project company and RAO or another creditworthy entity, ensuring the sale of capacity and energy to the wholesale market in accordance with the tariff structure outlined in section 4.1.4.2,

- Heat supply agreement between the project company and the Mostovskoy Administration, for the supply of district heating to residential areas surrounding the plant,

- Long term fuel supply agreement between the project company and RAO Gasprom, for the continuous supply of natural gas to the project,

The operation and maintenance of the plant will be carried out by the staff of Kuban GRES, with initial support from outside contractors and equipment suppliers who can provide assistance and training for the operation of new technologies as necessary.

4.1.4.2 Tariff Structure

Based on the conclusions regarding the project's integration into the wholesale market for power presented in section 4.1.3, the tariff structure for the project will need to meet the following requirements:

- Ensure a minimum level of return on equity for the investors of the project, based on prudent maintenance and operating practices of the owners,
- Ensure the project's ability to meet debt service requirements,
- Encourage the efficient operation and dispatch of the plant.

Based on the above objectives, and in light of the experience of the Russian power sector with various tariff structures, an initial concensus regarding the adoption of a two-part tariff structure has been reached within RAO and with the Federal Energy Commission (FEC). The tariff components should in general be structured as follows:

A) Fixed Capacity Charge Component (Fixed Monthly Payments for Plant Availability):

Debt service, with indexation to the currency of the debt,

Fixed operations and maintenance costs, including depreciation, with ruble components indexed to inflation, and hard currency components indexed to exchange rate. Standards for fixed O&M costs, including base employment levels and expenditures, would be agreed upon among the signatory parties and the FEC.

Return on equity, indexed to currency exchange rate, with a provision of adjustment to changes in tax regulations affecting investor profits,

Other fixed costs, including insurance, property taxes, permitting fees, payments for government guarantees, and other taxes and duties.

Fixed capacity payments should be made to the project company by RAO for plant availability, regardless of dispatch. The project company would be obligated to maintain plant efficiency standards at all times, as outlined in the Power Purchase Agreement (Section 4.3).

B) Energy Charge Component (Variable Payments Based on Dispatch):

Cost of fuel, allowing a pass-through of fuel costs incurred to meet dispatch requirements, *Variable O&M costs,* allowing for recovery of all variable operations and maintenance costs incurred to meet dispatch and capacity requirements,

Additional Profit component, to provide incentives for the operation of the plant, and allow incentives for maximizing the efficiency of operations,

Other fees, to ensure recovery of all costs incurred in response to the dispatcher's requirements of the plant, including payments for frequent starts, hot stand-by, spinning reserve, and higher operating costs due to unexpected variations in ambient temperatures. Penalties imposed on the project company for not meeting availability and performance requirements defined in the PPA would not be included in pass-through costs.

Krasnodar GRES's variable energy charge may, during the initial period of operation, be determined through the traditional method of periodic rate filings with regulators, and incremental adjustments of wholesale generating tariffs through justification of expenditures by the generator. As a more competitive system of dispatch is implemented over time, through the use of bidding mechanisms, the plant's marginal cost would be determined by the market, thereby providing additional incentives for efficiency improvements.

4.1.5 Accommodating the Project in Evolving Price Zones

The current approach to the formulation of tariffs is based on the philosophy of a unified national wholesale market for electric power and capacity. The operation of the power sector as a single market, however, can accommodate differentiated tariffs for suppliers of power to the wholesale market, and differentiated tariffs (including regional price zones) for the power supplied from the wholesale market.

The tariff impact on the national wholesale market of commissioning Kuban GRES can be analyzed in the context of two possibilities for the evolution of pricing methodologies in the market, as follows:

A) Maintain Current Pricing Approach

As a participant in the wholesale market, the relatively higher tariffs of the 900 MW Krasnodar GRES plant (3.7-4 cents) can be blended with the wholesale tariffs of more than 212,000 MW of additional generators nationwide, thereby producing a minimal incremental impact on wholesale tariffs to utilities. The disadvantage of this approach, as pointed out above, is that it would, in the short term, impose a burden (although small) on all consumers to pay for a plant from which they do not necessarily benefit.

B) Establish Regional Price Zones

The second option is to establish the North Caucasus, along with each of the 6 other major regions in the country, as separate price zones. Tariffs in each price zone would reflect the cost of generation in that zone, and the cost of importing power from adjacent zones in the event of a deficit. In the case of the North Caucasus region, therefore, this approach would limit the "blending" of the Krasnodar GRES tariff with the generation base of that region, and this region alone will absorb the rate impact caused by Krasnodar GRES.

The limitation of the "blending" of the Krasnodar GRES tariff to within one regional price zone (either through establishment of separate pools or through changes in RAO accounting methodologies) will have a measurable impact on the North Caucasus wholesale tariff. The North Caucasus division of the wholesale power pool currently includes two generating plants, Stavropolskaya and Nevinnomyskaya plants with 2136 and 1117 MW of available capacity respectively. A fourth plant, the 1734 MW Novocherkask facility, is also in the process of being transferred from Rostovenergo to operate on the wholesale market. The average weighted (wholesale) tariff of RAO's North Caucasus grid was 104.1 R (2.3 cents) per kWh in 4th Quarter 1995. On the other hand, the Krasnodar GRES tariff with a range of 3.7-4 cents (levelized, including VAT, as calculated in Chapter 3), combined with other project-related components including cost recovery for the gas pipeline and transmission line investments, may result in a total project-related cost of electricity of 4.2-4.5 cents.

According to RAO, this added cost for the additional 900 MW of power would result in an increase of the wholesale cost of power in the North Caucasus region to approximately 2.8 cents (assuming 4 cents tariff for Krasnodar GRES). This would represent a 17-20% increase in current wholesale tariff levels of the North Caucasus region. As power purchase costs currently represent approximately 31% of KubanEnergo's average tariff component (see section 4.5) the resulting impact of the increase in wholesale costs on KubanEnergo's average tariff would be close to 10%. Tariffs of StavropolEnergo, the only other large consumer of power from the North Caucasus wholesale market, would also be impacted by this increase. Thus, the sensitivity of StavropolEnergo and its regulators should also be considered.

The ultimate decision regarding regional vs. national blending of the tariff rests with the Federal Energy Commission (FEC). However, it appears that the FEC and RAO are intent on implementing separate pricing zones within the national wholesale market for power as the ultimate structure for the sector.

4.1.6 Key Issues for Resolution

The following are key issues arising from recommendations presented above, to be addressed through a cooperative effort of Kuban GRES, RAO, and the FEC. A joint working committee including representatives of these parties has already been formed and begun work towards resolution of these issues.

1) Capacity of RAO to Purchase Power

Issue: The current role of RAO EES Rossii, as manager of the wholesale market, is limited to that of a "market-maker" which organizes bulk power trades between surplus utilities or independent generation facilities, and deficit utilities or other purchasers of wholesale power. RAO does not take title of the electricity transmitted through the wholesale market, but acts as a clearinghouse for settlement of accounts between sellers and purchasers based on a tariff adopted by the FEC for various geographic zones. RAO, therefore, does not itself actually purchase or sell power and is not liable for any defaults in payments by purchasers. It would currently not be able to enter into a PPA with Kuban GRES, where RAO is defined as a power purchaser, without specific authorization to do so by the FEC. This needs to be resolved in order to ensure that Kuban GRES has a creditworthy and reliable purchaser.

Suggested Approach: One alternative is that the Government, until formation of the FEC, authorize RAO to resume its function as purchaser. This would enable RAO to provide the assurances necessary for development of the Krasnodar project as well as similar projects in the future. A second alternative is for the Central Dispatch Agency to execute the power purchase agreement with Kuban GRES, assuring priority payment to purchases from the plant, with a back-up payment guarantee from RAO.

2) Tariff Structure

Issues: The two-part tariff currently used for settlement of accounts for independent plants operating on the wholesale market is to a large extent similar to the structure proposed in the feasibility study. However, the structure of the capacity and energy charges proposed in the draft PPA differ in structure and content from the current system. Also, it appears that monthly adjustments in the Krasnodar GRES tariff, as suggested in the study, would not be feasible under the current system, which only allows for quarterly adjustments.

Suggested Approach: It is recommended that a tariff structure that balances investor needs with the necessity to provide incentives for an efficient wholesale market be adopted, similar to the approach recommended above. It is also suggested that a contractual system of tariff regulation be adopted in the PPA, which will enable the

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parties to adjust tariffs on a monthly basis using specific tariff adjustment mechanisms, with quarterly or annual scrutiny by the FEC.

3) Determination of Allowed ROE

Issues: The feasibility study for the Krasnodar Project currently assumes a 15% return on equity (ROE). It is necessary to coordinate the allowed minimum ROE level that the project participants (whether domestic or foreign) will receive, with the FEC.

Suggested Approach: The Implementation Agreement (IA) to be executed between the government and Kuban GRES should include the agreed-upon allowed ROE.

4) Government Guarantees

Issues: Only the guarantee for the World Bank loan has been approved by the Government. Additional governmental assurances regarding regulatory risks have not been addressed.

Suggested Approach: Key principles of the PPA, including tariff structure, terms and frequency of adjustment, and allowed ROE, as well as other guarantees that may be required by investors and agreed-upon by the government, should be included in an Implementation Agreement. Furthermore, the Government should assure Kuban GRES that its shareholders will be adequately compensated for all governmental intervention, including change of law and regulation, that may impact the project.

5) FEC not Yet Formed

Issue: As of January 29, the Federal Energy Commission (FEC) has not been formed, despite a decree last year forming a new FEC and calling for establishment of professional full-time commissioners and staff. It is not clear when a new chairman and staff of the FEC will be assigned, and what policies the new body will pursue. For a private power project such as Kuban GRES to proceed forward, its regulatory environment should be clearly defined at the outset for the duration of the project.

Suggested Approach: The Government of the Russian Federation, primarily through the Ministry of Economy, has assumed some of the functions of the FEC, including regulation of current wholesale tariffs. It is suggested that RAO and Kuban GRES, until formation of the permanent FEC, apply to the Government for resolution of key issues identified here. Key principles of the PPA, including guidelines for tariff structure, terms and frequency of adjustment, and the allowed ROE could be outlined in an Implementation Agreement executed between the Government and Kuban GRES. This agreement would also include a provision ensuring that future

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FECs will not change these principles, and changes could be introduced into the contract only through mutual agreement with Kuban GRES.

6) Implementation of Recommendations

Issue: The feasibility study prepared by the consultants, and generally reviewed by RAO, recommends general principles for structuring the Krasnodar Project and related agreements. However, finalization of these agreements prior to financial close in June of 1996 will require significant coordination between Kuban GRES, RAO, the World Bank, and the FEC. Organization of this joint work needs to be addressed at this stage.

Suggested Approach: It is suggested that an agreement be reached regarding the organization of a joint committee, with representatives of Kuban GRES, RAO, the World Bank, and the FEC, to most expediently resolve matters related to agreements and guarantees required to ensure financing of the project.

4.2 Corporate Plan for Kuban GRES

4.2.1 Introduction

This chapter presents a corporate plan for the new project company Kuban GRES, in a format such as to facilitate the preparation of a loan package which will meet the requirements of the World Bank. The remainder of this chapter is organized as follows:

4.2.2 Project Characteristics
4.2.3 Formation of Kuban GRES
4.2.4 Objective
4.2.5 Initial Undertaking
4.2.6 Capital Structure and Founding Shareholders
4.2.7 Principal Office
4.2.8 Term of Incorporation
4.2.9 Management - Organization Structure and Responsibilities
4.2.10 Overall Governance
4.2.11 Initial Project Undertaking
4.2.12 Ongoing Power Utility Operations
4.2.13 Financial Controls and Performance Management
4.2.14 Implementation Schedule
4.2.15 Training Program & Schedule

4.2.2 Project Characteristics

Independent power generation ventures are highly capital intensive, extremely complex, and medium to long-term gestation projects. Hence, ensuring project success requires planning, evaluation, and allocation of resources at all stages of project maturity, from project conception through to continuous station operations.

The Krasnodar GRES project has been the subject of such careful evaluation and planning, and will in the normal course of events realize the benefits projected. Key factors that will contribute to the project's success include:

The Need for Power

The Krasnodar Krai region, which is part of the North Caucasus Unified Power System, has been experiencing electricity shortages and the situation is expected to get worse in the near future. This project addresses the region's need for additional power generation capacity by building one or more power generation facilities.

The North Caucasus UPS has an effective system capacity of only 8387 MW during winter in spite of having a combined installed capacity of 10,557 MW. Derating of units due to age and state of repair, deterioration in the quality of available fuel, and seasonal impacts on hydro capacity are key reasons for the disparity between dispatchable and installed capacity. Additionally, power received in the past throughUkraine has been limited since the interconnection is no longer in operation. The power deficit is projected to reach 2000 MW by the year 2000 - assuming conservatively that the existing aging equipment will remain operational over the next several years and the drop in consumption has stabilized.

The Krasnodar Krai is the region with the greatest power deficit within the north Caucasus region - relying on imports from neighboring utilities and RAO for approximately 60% of its electricity consumption. While several programs including hydroelectric plant additions, building a new 500 KV transmission link, addition of combustion turbine capacity, and equipment replacement projects are currently underway to bring additional capacity on-line between 1996 and 2000, as the least lost plan study indicates, the addition of approximately 940 MW of thermal capacity in the North Caucasus region in the immediate future continues to be a requirement for meeting local need.

The Site:

The site at Mostovskoy is the most expeditious for this undertaking. It has already been studied for appropriateness as a power plant site -- first as a site for nuclear plant operation in 1981, and adequately as a combined cycle station (up to 1350 MW) in 1991. As the least cost plan indicates, this gives it a site development timing advantage over the other two feasible sites in the region, and offsets its relative disadvantage vis-à-vis proximity to major lead centers in the region. In addition, the land for the project has already been secured from the local government.

Technology:

The plant design uses proven technology: 900 MW combined cycle plant - two blocks of 450 MW each; each block consisting of two combustion generators, two heat recovery steam generators, and one steam turbine generator. District heating steam, water boilers, and heat exchangers are separately included.

Clean Fuel:

The proposed plant will be fueled by natural gas as the primary fuel - this is both environmentally sound, conveniently accessible to the site, and will be available in sufficient quantities during the expected lifetime of the project.

The Owner Group:

RAO EES Rossii, RAO Gasprom AO KubanEnergo, the Unified Electric Energy Complex Corporation, AO Energy Machine Building Corporation, and AMOCO expect to constitute the owner group sponsoring the Krasnodar project. These investors, will bring both a depth of local expertise and financial credibility, as well as a diverse range of material and management skills, to the enterprise. For example, RAO EES Rossii, as the primary player in the electricity sector in Russia, can contribute significantly to Krasnodar Project's dispatch and integration efficiency, as well as keep all parties abreast of the developments in ongoing restructuring of the electric energy sector.

RAO Gasprom, as the fuel supplier, can aid significantly in minimizing fuel related problems. A similar case can be made for each of the other participants. Each one brings a specific and unique advantage to the owner's table, and each participant has its own investment in the project's success.

Structured Project Agreements:

IPP success depends on the structure, completeness, clarity, and enforceability of the various key project agreements. The drafts of the proposed agreements are as follows:

- Shareholder agreement
- Fuel supply agreement
- Power purchase agreement
- Heat purchase agreement
- Implementation agreement

These drafts generally conform to the structure, form and content of contracts executed in successful projects elsewhere.

Other related advantages include:

- A generally favorable regulatory regime.
- Potential for the availability of local manpower and skills.

4.2.3 Formation

A new limited liability company to be known as Kuban GRES Company Limited is to be established as a Russian joint stock company under the laws of the Russian federation pursuant to the terms and provisions set forth in this plan and agreements described in other chanters and annexes in this report.

4.2.4 Objective

The objective of the Kuban GRES Company is to develop, finance, construct, own, operate, and maintain the power generation at Mostovskoy and sell electricity and heat under long term Power Purchase Agreement as primary sources of income. Kuban GRES Company is intended to be a model for future Independent Power Producers in Russia. Kuban GRES may transfer the know- how it acquires in setting up other similar projects and may participate in leading the development of such projects including taking equity positions.

4.2.5 Initial Undertaking

The initial undertaking of Kuban GRES Company will be to develop, design, finance, construct, operate and maintain a power generation facility of 900 MW with a potential revenue generation capability of $194 million at an average tariff of 2.9 c/kwhr. The facility will consist of two 450 MW combined cycle modules. Each module consists of two 150 MW combustion turbines, one 150 MW steam turbine and two waste heat recovery steam generators. Natural gas will be the proposed fuel for the facility, with diesel as the emergency back-up fuel (Task 1 - Data). The initial undertaking, summarized in Figure 4.2-1 will include all associated contracts, licenses, permits, agreements and approvals necessary for the development design, construction, financing, operation and maintenance of such a facility, including but not limited to the following:

- Development/Shareholder Agreement
- Power Purchase Agreement (RAO EES Rossii is expected to purchase all output from Kuban GRES)
- Engineering, Procurement and Construction Contracts (expected to be awarded through competitive bidding process)
- Fuel Supply Contract (RAO Gasprom)
- Financing Agreements
- Environmental Permits

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4.2.6 Capital Structure and Founding Shareholders:

Preliminary Capital Structure ranges for the Kuban GRES Company, as indicated in Chapter 3, are 65-70% debt (to be raised in conjunction with the World Bank) and 30-35% equity (contributed by Russian and other foreign investors). While equity participants of differing rights and privileges are envisioned for the longer term, the founding shareholders are respectively:

	Option1	Option 2
• RAO EES Rossii	34-37%	28%
• AO KubanEnergo	18-20%	14%
• RAO Gasprom	25%	20%
• Unified Electric Energy Complex Corporation	10%	8%
• AO Energo Machine-Building Corporation	8-10%	8%
• Potential Foreign Investor (AMOCO)	0%	20-22%

The distribution of shares indicated above is still preliminary and is likely to change. Also, the group may include a qualified foreign investor based on the terms of involvement offered by such an entity.

4.2.7 Principal Office:

The address of the principal office of Kuban GRES Company, unless hereafter changed by an appropriate resolution by its Board of Directors shall be 352550, Village Mostovskoy, Krasnodar Krai, Russia.

The official records of the company shall be maintained at such office.

4.2.8 Term of Incorporation (Foundation Agreement)

Except as provided in this plan and in agreements attached to this report, the term of incorporation shall commence from the date of its registration and shall continue for an indefinite period.

4.2.9 Management - Organization Structure and Responsibilities (Task 2)

As befitting a new genco, the management structure roles and responsibilities of Kuban GRES Company Ltd. are described here in three distinct categories, namely:

- the overall governance structure for Kuban GRES as laid out in its registration and shareholders' agreements.
- the structure, roles and responsibilities necessary for successful launch of its initial generating station undertaking (Task 2)

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- the structure, roles and responsibilities necessary for successful ongoing operation as an established generating company or power utility (Task 2)

4.2.10 Overall Governance

The Kuban GRES Company Ltd. will be governed by a Board of Directors. The total member of directors shall be 12, designated by the founder and sponsor shareholders. The Board of Directors of Kuban GRES Company Ltd. will elect a Chairman, who with his/her fellow directors will appoint a General Director, a Chief Financial Officer and Vice President, a Manager of Technical Affairs, a Manager of Construction, an Engineering Manager and a Manager of Procurement. Figure 4.2-2 is indicative of the functional responsibilities under the various managers.

4.2.11 Initial Project Undertaking

Figure 4.2-1 is representative of the sequence and the tasks necessary in identifying, developing, financing, designing and commissioning a power generation facility. The following describes the status of these tasks in the Krasnodar GRES.

Project Screening Process

- Project selected.
- Preliminary feasibility and site selection.
- Review completed.

Project Team Formation

- Major Project Partners identified:
  1. Equity Contributors
  2. Power Purchaser
  3. Heat Purchaser
  4. Fuel Supplier
- Other Partners with potential major financial or managerial contributions such as equipment suppliers and architect-engineer-contractor are actively being sought.
- The preliminary roles and responsibilities and specific organizational structure are developed.

Ownership / Partnership Agreements

- Drafts of major project owner agreements - in various stages of revision - have been developed. These include:
  1. The foundation agreement on setting up a joint stock company
  2. Rules for the joint stock company
  3. Principles of a shareholder's agreement

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- These agreements identify various parameters including contributions, liquidation rights, responsibilities and scope of participation.
- Drafts of other major agreements such as the fuel supply agreement, the power purchase agreement, and the construction contract have also been developed.
- An additional key contract "the implementation agreement" providing a financial backstop provision has also been drafted.

Form Project Company

This stage represents a major go/no go step in the power generation development cycle: Having identified a specific project and selected partners, the owner group commits to specific, scheduled expenditure for detailed project review, and to the formation of a special purpose company as vehicle for the project's finances and management.

- The decision to form a special purpose company, i.e. Kuban GRES Co. Ltd. has been made.
- Detailed analyses and evaluations beyond the initial feasibility review are underway - underlining the continued confidence of the owner group of the viability of the project.
- Preliminary definition of requirements for selecting an architect engineer are being developed.

At this stage, the owner group will target its efforts toward identifying the key contractors - i.e. architect/engineers in order to proceed with converting the initial project data into a detailed project design. The detailed project design drives subsequent key activities such as casting, developing bid specs, and letting construction and procurement contracts.

Permitting

- Environmental Assessment Approved by the Russian Ministry of Ecology in January 1996.
- Given that the Mostovskoy site has been reviewed twice - once in 1981 for a nuclear plant setting and in 1991 for fossil fuel (1350MW) - the owner group does not expect to have any major permitting hurdle.

EPC Contracts, O&M, and Fuel

- As indicated earlier, working drafts of various such contracts have been developed. Key signatories have been identified and in many instances are near final agreement.
- Vendor training of Kuban GRES personnel has been included in equipment contracts.
- GasProm is the primary fuel supplier.

Tax status of project

- The project will be taxable under Russian tax rules.

Need for Additional Equity Resources

As mentioned above, the distribution of shares among the current shareholders may take place in the event that one or more of the proposed shareholders can not meet their equity commitments.

Selection of Expert Consulting Services

- Ongoing, as necessary, for project development
- Tender documents in preparation for selection of Architect/Engineering services throuoh competitive bidding, for construction management support.

Selection of Lenders

- The World Bank is expected to be the major lender.

Risk assessment

- Ongoing.
- Preliminary risk analyses have been completed considering various contingencies such as lower demand, startup delay, delay in customer payments, problem resolution, lower tariff, higher gas costs.
- Results are presented in detail in section 3.3 of this report.

Proformas / Income Statement / Balance Sheet / Cash Flow

- Completed.
- Chapter 3 provides details.

The remaining major tasks in the process (i.e. preparing a prospectus for raising capital, obtaining preliminary financial commitments, finalizing financing documentation, obtaining board approval, and financial closure) are expected to be completed in a relatively timely sequence given the advanced stage of the various development activities to date. In this instance, since the parameters of the initial project undertaking have been defined (Chapters 1,2,3), the project development organization which will be charged with construction and commissioning of the project is defined herein.

Project Development Team

Upon formation of the development company Kuban GRES, the following positions will be staffed in order to establish the leadership organization required to ensure a successful development and implementation undertaking:

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- Team Leader during development stage, responsible for business and financial structure of project. General Director of Kuban GRES during operations General qualifications should include:

  - Education: Degree in Engineering and preferable advanced degree in Economics
  - Knowledge of
    - multiple disciplines in engineering field
    - power supply, transmission, and fuel procurement contracts
    - complex business management
    - tariff design
  - Experience:
    - senior role in electric utility management
    - prior leadership in management and structuring of complex power projects, preferable internationally,
    - financing of high value and complex projects
  - Responsibilities and Reporting Relationships:
    - reports to Chairman and Board of Directors of Kuban GRES
    - coordinates and supervises activities of other project directors, i.e. Finance, Construction, Procurement, Technical
    - represents owners' interests in field, responsible for effective implementation of project from initial structuring to commercial operations
    - principal and sub contract development, negotiation and award
    - liaison with federal and local authorities, lending agencies and owners to report, assess and prioritize project activities
    - organization development, policies and guidelines

- Director of Finance - should be the Controller of joint stock company (See Figure 2.7-1). Responsible for financial structuring, tariff setting, project agreements, and regulatory relations. General qualifications should include:

  - Education: Specializing in Accounting or equivalent recognized professional qualification
  - Knowledge of
    - project agreements development for independent power producers
    - financial modeling, tariff design and rate filings
    - Russian and Western accounting and financing principles
    - corporate legal issues
  - Experience:
    - arranging debt and equity financing for complex projects
    - budgeting, cost control, and capital asset management for similar business
    - payroll and benefits administration
    - project based management and accounting systems
    - Russian tax system

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- Responsibilities and Reporting Relationships:
  - reports primarily to General Director, liaison with Chairman and Kuban GRES Board of Directors
  - liaison with shareholders, regulatory agencies, tax authorities, lenders, power purchaser, fuel supplier
  - all financial, accounting, legal, regulatory, human resource, information systems functions
  - asset/liability, cash flow management
  - financial modeling and analysis, tariff setting
  - external reporting
  - policies, procedures and guidelines for financial and administrative activities
  - customer billing and collections

- Construction Manager - Responsible for project construction, preparation of tendering/procurement documents during development stage, and overall oversight of A/E activities during construction - Subsequently Manager of Construction, Operations and Maintenance (See Figure 2.7-1). General qualifications should include:

  - Education: Degree in Engineering, preferably advanced degree in Engineering
  - Knowledge of
    - procurement and negotiations all aspects of plant implementation contracts
    - lump sum and reimbursable contract management
    - multiple package construction management
    - cost and schedule control
  - Experience:
    - managing multi-disciplinary project engineering activities for major engineering, procurement, construction assignments in similar industries
    - sourcing, hiring and managing subcontractors on large complex contruction projects
    - power plant operations and supervision
  - Responsibilities and Reporting Relationships:
    - reports to General Director
    - supervision of all site operations
    - project cost and schedule reporting and analysis
    - development and implementation of master project construction schedule and plans
    - developing contract terms and specifications
    - vendor selection, contract award
    - coordination of in-house and external design, estimating, finance and procurement groups
    - shop drawing reviews
    - construction practices, procedures and policies

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- Engineering Manager - Responsible for overseeing all technical aspects of design, procurement and plant testing and operations. Subsequently Manager of Engineering and Technical Services (See Figure2.7-1) General qualifications should include:

  - Education: Bachelors degree and preferably Masters Degree in Engineering
  - Knowledge of
    - field engineering
    - site operations
    - multi-disciplinary and multi-team contractor management
  - Experience:
    - managing multi-disciplinary project engineering activities for major engineering, procurement, construction assignments in similar industries
    - overseeing and coordinating in-house and vendor engineering and design activities
    - developing proposals and requests for quotations/technical specifications for large design/build/operate infrastructure projects
  - Responsibilities and Reporting Relationships:
    - reports to General Director
    - overall responsibility for all engineering and technical quality assurance
    - development and implementaiton of master project plan and schedule for engineering activities
    - development of finalized detail project design documents for project costing and analysis

- Procurement Manager - likely to be Manager of Purchasing, Transportation and Stores during plant operations (See Figure 2.7-1). Responsible for development of tender/procurement documents and contractor oversight during project development and implementation. General qualifications should include:

  - Education: Bachelors degree and preferably Masters Degree in Engineering or Economics
  - Knowledge of
    - specifications development, contract development, negotiations
    - competitive tendering procedures
    - procurement, expediting, transportation, inventory management
    - Russian customs clearance
  - Experience:
    - management of purchase of goods and services for major projects
    - oversight of materials management and logistics for similar construction projects
  - Responsibilities and Reporting Relationships:
    - reports to General Director
    - vendor qualification, selection and management

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- development of requests for quotation
- functional progress reporting, coordination with overall project cost and schedule requirements
- stockroom, warehousing and site material policies, procedures and management
- logistics and traffic management
- development and implementation of project goods and services supply plan

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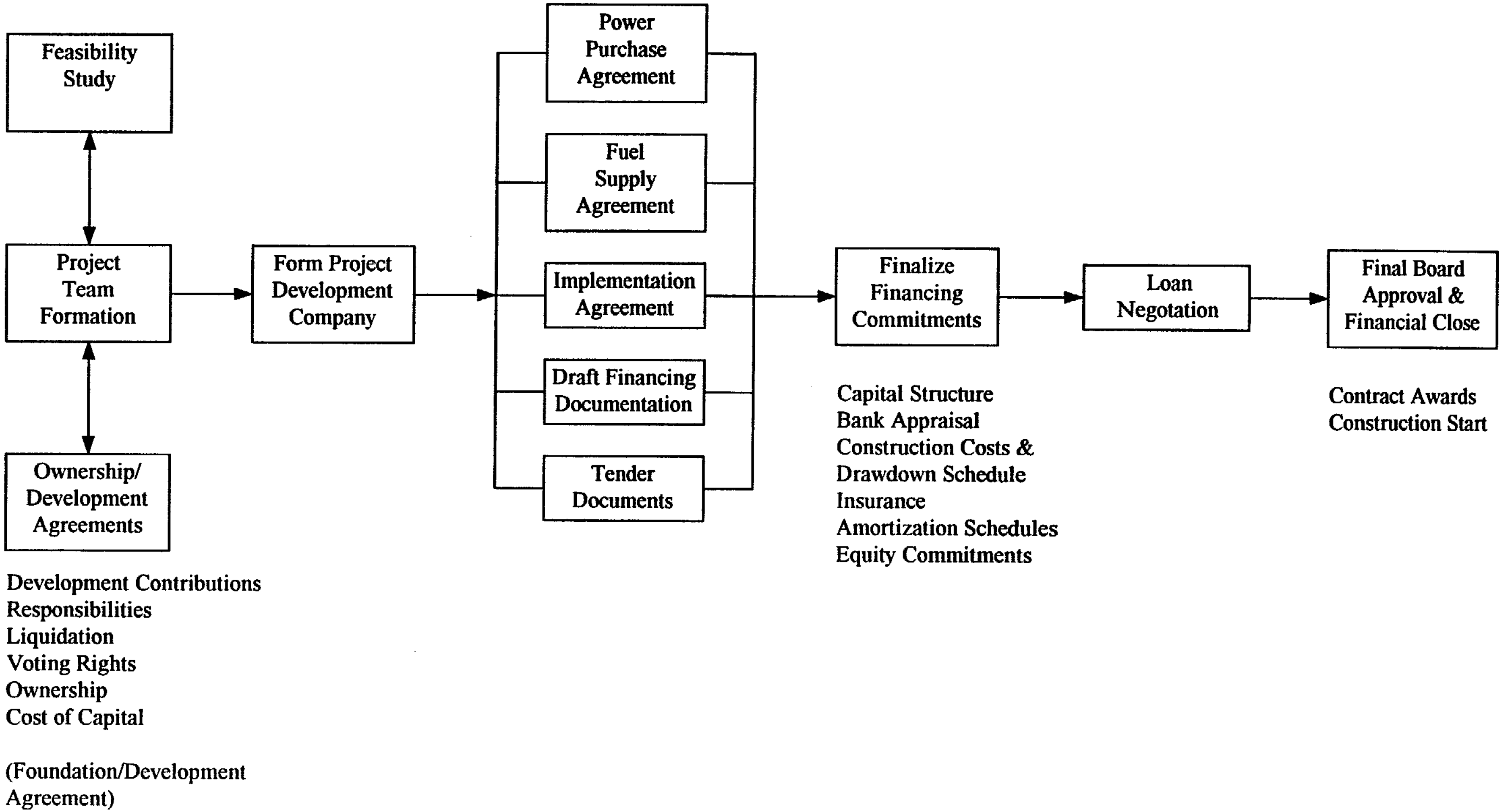
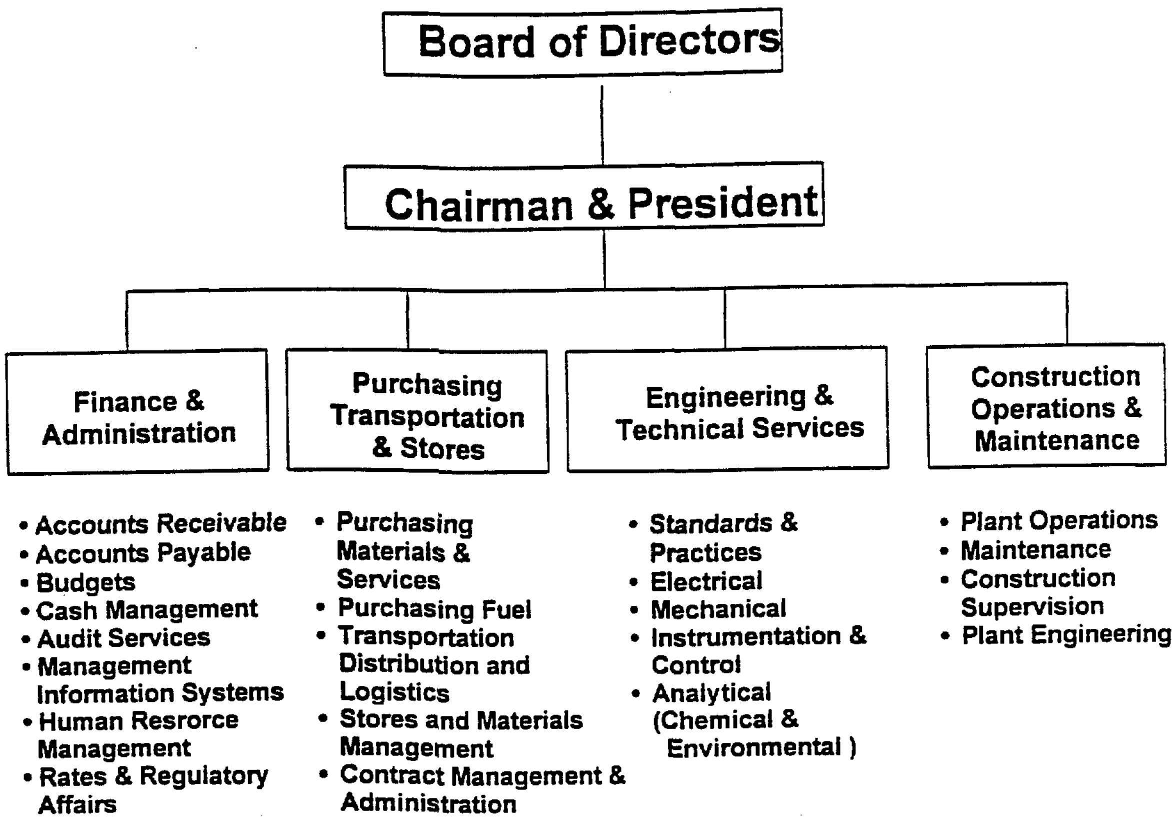
FIGURE 4.2-1
Summary of Development Process



Kuban GRES Company LTD.

Initial Organization — Figure 4.2-2



4.2.12 Ongoing Power Utility Operations

Kuban GRES will be structured to take over from the project development organization at the close of construction and to transition smoothly into an organization representative of power utility operations. Figure 4.2-2 is a preliminary organization structure proposed for ongoing operations. The organization structure and functions depicted here would enable the performance of such duties. Table 4.2-1 is indicative of allocation of responsibilities based on such an organization and process flow.

In order to set an example for future projects, Kuban GRES staffing should be kept to a minimum level necessary. Primary emphasis should be to contract for services, rather than direct hiring. The operation and maintenance of the plant is a good example where it is recommended that KubanEnergo, being the neighboring utility with its human resources, already oriented and trained in utility business is likely to provide input into operation.

The overall staffing at the plant may be based upon experiences of other western utilities. For example, a similar plant in the United Kingdom is staffed with 38 personnel. Considering the difficulty of logistics at the remote site, the limitations in the amount of outsourcing to local companies that can be relied upon, and given the difficulties in the amount of paperwork required to perform such business in Russia, an overall staffing of 167 personnel directly employed by Krasnodar GRES is recommended as initial complement, as presented in Chapter 2. This staffing level may decline as efficiencies improve and outsourcing opportunities become more realistic. Services such as O&M, security, legal and regulatory aspects, plant betterment, janitorial, cafeteria, groundskeeping services, and major overhauls can be outsourced, with Kuban GRES personnel managing those contracts.

4.2.13 Financial Controls and Performance Management

Table 4.2-1 & 2, and the series (list) of recommended reports to the executive management shown below both provide a relatively large list of indicators to help manage the performance of Kuban GRES at the corporate as well as the functional level.

A suggested minimum list for executive management would include indicators presented below, most of which are already included in power plant performance reporting guidelines in Russia.

Financial
- Financial Highlights
  - Revenues
  - Fuel Expense
  - O&M Expense excluding fuel

Plant operations
Corporate administration
Earnings to Common
Return on Equity
KWH Sales
Accounts Receivable
Income Statement
Balance Sheet
Total payroll vs. budget
Materials & supplies inventory

Fuel & Production

Fuel cost per kwh generated
BTU per net kwh generated
Plant net capacity factor
Plant equivalent availability factor
Plant forced outage rate
Emergency fuel inventory (hours of burn)

Human Resources

Total employees vs. approved positions
Lost time accident rate
Turnover rate

Statement of Significant Events During Period

This section should contain a brief statement of unusual or significant events that occurred during the reporting period. This would include such events as an unplanned outage of a unit, and interruption to fuel supply, a serious equipment failure, a serious injury to an employee, etc..

However to be effective performance, measures and indicators in the list above and in Table 4.2-1 need to be timely and accurate, as well as comprehensive. Implementing existing KubanEnergo processes and systems at Kuban GRES is not likely to provide data or information that is relevant or timely for management. The measures shown here are dependent on well developed and quite routine data collection, reporting and processing methods. Kuban GRES will attempt to deploy as many of the proven systems as possible to facilitate management control. In addition to enhancing financial measurement and management ability through the use of such systems and indexes, financial control will be further enhanced by the clearer delineation of internal audit procedures, policies and guidelines; clear definition of project/cash/financial expenditure approval levels and authorities. Appendix J is indicative of such guidelines.

4.2.14 Implementation Schedule

The following is an implementation plan developed to provide a clear roadmap to Kuban GRES in project development, staffing, training and corporate systems. A detailed implementation schedule is presented in Table 4.2-3.

A) Development Stage

1. Formation of Special Purpose Company - Kuban GRES.

- Development/Shareholders Agreement
- Legal Registration
- Ratification of corporate Charter
- Commitment to capital contributions and project expenditures
- Appointment of Board of Directors
- Appointment of Leadership Team/Corporate Officers and executives

  - General Director (Kuban GRES)
  - Director of Finance (Controller -KGC)
  - Engineering Manager (Engineering and Technical Services Manager-KGC)- Construction Manager (Construction, Operations and Maintenance Manager - KGC)
  - Procurement Manager - (Purchasing, Transportation and Stores Manager - KGC)

2. Orientation of Corporate Officers and executives (See Organization Chart in Figure 4.2-2)

Orientation:
- Definition of roles and responsibilities
- Review of current project progress status
- Identification of major milestones in the immediate future quarter
- Review of project analyses and documents
  - Costs, budgets and expenditure schedule and commitments
  - Major project agreements (fuel supply, power purchase, other)
  - Bid and tender documents for award of equipment and construction contracts

3. Complete financial structure and project agreements
- Confirm lender commitments
- Debt and equity ratios
- Costs of capital
- Finalize equity commitments

- Government Guarantee for World Bank Loan
- Project Agreements (power/heat purchase, fuel supply, implementation)
- Insurance
- Financing documents (loan or project agreements) and loan negotiation
- Land Rights

4. Obtain final board approvals and move to financial closure; first drawdown of financing.

B) Construction Stage

5. Estab'ish and staff project management organization (See Figure 4.2-2).

- Develop and define project procedures and systems, including:

- Organizational roles and responsibilities
- Performance measurement and evaluation policies
- Procurement practices and guidelines
- Budgetary approval levels and authority
- Progress tracking and reporting requirements
- Management reports and requirements
- Exception and contingency management procedures
- Personnel selection, hiring and development policies and procedures
- Internal audit guidelines and requirements
- Management information systems and requirements
- Financial and accounting reporting policies

- First Line Management:

- Budgets and Cost Control Supervisors (Administrative Services Manager)
- Human Resource Management and Payroll Supervisor
- Project and Plant Security Services (may be contracted out)
- Project Direct Engineer - Electrical and Mechanical Engineering
- Project Chief Engineer - Controls Instrumentation Systems
- Project Chief Engineer - Civil and Structural Engineering
- Project Engineer - Planning and Scheduling
- Project Engineer - Field Engineering and Construction
- Project Engineer - Document, Control and Change Orders for Systems Management
- Field Quality Assurance Supervisor
- Buyer - Materials
- Buyer - Services and Contracts Administration
- Stores and Materials Supervisor

- Secretarial and Office Support Personnel
- (Phase-in) Site Security, Janitorial, Other Services

6. Project Specific Training for Project Management Organization

- Orientation for first line organization (supervision)
- Project overview ; key players, roles and responsibilities, major project milestones, key constraints and deliverables

- Topical training covering several areas such as:
- Management of large complexes
- Construction projects - principles and process
- Roles and responsibilities
- Budgeting, planning and cost control
- Progress measurement and evaluation
- Computerized planning, scheduling and reporting systems
- Development of work packages for contractors
- Management of architect and engineer; constructors and other major contractors
- Contract management, administration, principles and process

7. Award contracts / Project Construction Start

- Various project scheduled events in accordance to timeline in Chapter 2.

8. Installation and implementation of Management Information Systems (Sept. - Dec. '96):

- Project construction reporting
- Financial performance reporting
- Operations performance reporting

9. Begin transition to plant operations staffing (See Figure 2.7-1)

- Define and establish (outline) ongoing operations organization
- Identify plant operations / personnel relevant to installation of first simple cycle combustion turbine (first of several plant staffing operations)
- Define and develop operations procedures and guidelines in conjunction with equipment vendor/architect - engineer - constructor

10. Training and development of operations personnel (first of several to phase in at appropriate construction stage)

11. Construction Completion: Full Commercial Operation / Banking "Completion" Documents

C) Operation Stage

12. Transition to Plant Operations Organization

- Dissolution and restructuring of project management organization

The review of KubanEnergo's operations (Chapter. 4.4) clearly indicates the need for improvement in management reporting, data collection and analysis systems. The success of the project being undertaken at the Mostovskoy site, both during construction and later during operations in what is likely to be a restructured complete competitive energy sector, depends on the availability for accurate, timely and relevant management reporting systems.

The project implementation plan will include the necessary tasks to develop and deploy such systems - both during construction, the transition state of operations, and during full commercial operations.

The reporting and data collections systems will be developed to facilitate:
- Reporting by level of management (front line supervision, executive management, Board of Directors, etc.)
- Reporting by function (mechanical engineering, quality assurance, finance, etc.)
- Reporting by period (daily, weekly, monthly, etc.)
- Special purpose (event reporting, exception reporting, internal audit)
- Analyses (trends, variances, other statistical projections)

Where feasible or viable an attempt will be made to retain existing information or reporting systems using the review of KubanEnergo as a benchmark. However, it is likely that completely new mechanisms or major overhauls of existing reporting systems may be required to develop the necessary information systems capabilities. The training and development plans described elsewhere in the implementation plan accordingly reflect a significant emphasis on design development and development of management reporting systems. There are expected to be three major phases or categories of reporting and information systems to be implemented:

1. Financial and Accounting Systems

These will be the first systems to be developed. The range of data collection and reporting systems developed for this category will, unlike the remainder of systems to be described here, remain with Kuban GRES through both the construction, as well as the ongoing commercial operation phase. Major steps will include:

- Development of reporting requirements
- Owner Group
- Lender / Investor Requirements
- Regulatory Requirements
- Adoption of accounting policyDefinition of cost, work, budget or responsibility centers
- Development of appropriate procedures and policies (as described in earlier sections).
- Identification and selection of automated systems
- Deplcying manual procedures and systems
- Integrating system and process training schedules
- Installation and checkout of automated systems (major systems such as general ledger accounting, construction reporting, procurement, receivable and payables systems).

2. Construction Project Management Systems

The construction and transfer to commercial operation of power generation stations, especially of the nature being proposed here, is a well developed and established process consisting of a fixed and true capabilities and systems deployed by any of a number of architects, engineers, constructors and development organization. (Such a capability as outlined in the Raps will be a key requirement for selection as project engineers or constructor.)

As such, the Kuban GRES project organization will capitalize to the extent possible on available systems for project management. Similar emphasis on using existing systems will be placed on integrating upwards into the corporate reporting systems.

The major categories include:

- Developing hierarchy of reports
- Evaluating sufficiency of architect engineer - constructor's systems to facilitate project engineering procurement and construction progress reporting and tracking
- Developing function specific reports (e.g. for project engineers/mechanical and project engineers/civil and structural)
- Developing integration schemes for integrating construction reporting data with corporate level master project schedule to indicate major and critical path project events including financial payments and draw down schedules along with traditional engineering construction events.
- Identification and development of appropriate integrated systems (coordinate with earlier financial system seiection process)

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- Integrating system and process training schedules
- Deployment and checkout of systems

3. Plant Operations Systems

A key requirement for profitable operation in a competitive restructured electric sector will be the ability to manage actual costs and expenditures rather than rely on outdated information, or calculated, estimated or allocated costs. As indicated in the review of KubanEnergo operations (Section 4.4) such data are essential for the development of accurate tariff levels and hence accurate revenue capabilities.

As with the construction of power generating stations, the operation and maintenance of such stations including billing and collections is a well developed process in many Western nations, particularly in the UK and US. Much of the modern equipment and infrastructure likely to be proposed (such a requirement can be part of the RFP) for this project is generally capable of automated collection and reporting of significant operating level data such as hours and cycles of operation, MWhrs. generated, fuel consumed, failure modes, cariance from capacity, etc.

The project will build upon such capability in developing plant reporting and management systems. This effort may range from 18 to 24 months (October 1996 to March 1997). Key aspects of such development will include:

Developing a hierarchy of reports
- Reflecting levels of management, reporting period and functional requirements
- Developing data "roll-up" procedures to create such a hierarchy
- Identification of key management indicators or reports, including financial and operations reports, and other indexes such as for procurement performance, engineering man-hours, contractor management, inventory turns, accounts payable days, etc. (See Table 4.2)
- Integration of plant level data with work, cost or responsibility center assignment and chart of accounts requirements,

- Identification and selection of commercially available system packages such as for plant maintenance, capital project management, procurement, stores and inventory management, etc.
- Integration with system and process training
- Deployment and check-out of systems

TABLE 4.2-1: Overview of Responsibilities

	STRATEGIC PLANNING	ORGANIZATIONAL PLANS/O&M BUDGETS	CAPITAL PLANNING & BUDGETING	REPORTING	GENERATION PLANNING
Primary Planning Responsibility	Chairman, President	Functional Departments	Operations Maintenance Technical Services	Monthly Financial Operating Reports	Budgets & Estimation (Technical Services)
Review and/or Approval	Board of Directors	Functional Directors or Managers	Functional Directors President Board of Directors	Quarterly Financial Reports Operating Summaries	Functional Director President Operations
Analysis and/or Support	Relevant Special Management Committees;	Human Resources Administration Technical Services Planners Budgets & Estim.	Financial Planning Technical Services	Daily Financial & Technical Operating Reports	Budgets & Estim. Operations Technical Services

TABLE 4.2-2: Performance Indicators

CORPORATE PERFORMANCE INDICATORS	GENERATION & PLANT INDICATORS	FUEL SUPPLY MONITORING
Return on Average Com. Equity	O&M Budget Variance	Fuel Quality Index
Revenues & Receivables	Heat Rate Reduction	Price Index Comparison
O&M Expense	Capacity Factor	Fuel Inventory
Plant Availability	Forced Outage Indicator	O&M Cost
Plant Heat Rate	Equivalent Availability	Supply Reliability Index
Reliability	Accident Rate	
A&E Expense	Off-line Station Service	
Capital Expenditures	Absenteeism	

FINANCIAL INDEXES	
Profitability	Net Profits/Revenues Net Profits/Assets Revenues/Assets Oper. Profits/Assets or Revenues Return on Equity
Liquidity	Current Assets/Current Liabilities Cash Coverage & Interest Cash Coverage & Fixed Charges Cash Cov. & Construction Exp
Capital Structure	Debt/Equity Ratio Total Debt/Total Assets

OPERATING INDEXES	
O&M Costs	O&M Costs/Revenues O&M Costs/MWHrs Delivered O&M Costs/Capacity
Capital Expenditures	Capital Expenditures/Revenues Capital Expenditures/Assets
Reliability	Average Service Availability Index Forced Outage Rate Equivalent Availability Factor
Budgets & Planning	Actual vs Planned Variances (Expenditures, Costs, Manpower, Production Levels)

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TABLE 4.2-3
PROJECT IMPLEMENTATION SCHEDULE
IN PREPARATION FOR FINANCIAL CLOSE OF JUNE 1996

STEPS	ACTIONS REQUIRED	RESP.	SCHEDULE
A) DEVELOPMENT STAGE			
1. Complete Feasibility Study	A. To be Completed* 1. Incorporate Final Comments 2. Environmental Assessment Approved (January 1996) 3. Issue Final Report to World Bank & Investors	RAO & Consultants	February 1996
2. Form Shareholder & Development Team	A. Project Partner Team Identified* 1. RAO Board Approval of Equity Group 2. Initial Shareholder Commitments & Distribution of Shares	RAO	February 1996
	B. Development Team Representative to be Appointed* 1. Working Committees Formed to Initiate Coordination of Agreements Among Participants 2. Development Team Appointed & Authorized to Represent Kuban GRES Until Formation	RAO & Shareholders	February 1996
3. Form Project Company	A. Legal Registration, Shareholder Agreements* 1. Drafting of Charter & Foundation Agreements 2. Review of Agreements by Shareholders & Negotiation of Terms with Shareholders (Including Foreign Investor) 3. Determination of Equity Distribution 4. Finalization of Business Plan & Funding of Development Costs 5. Finalization of Shareholder Agreements, Charter Capital, Equity Contribution Schedules, Cost of Capital 6. Execution of Shareholders Agreement 7. Legal Registration of Kuban GRES Co. 8. Shareholder Meeting to Appoint Board of Directors 9. First Board Meeting	Kuban GRES Shareholders or Official Representatives	Feb/March 1996
	B. Appointment of Leadership Team*		Feb/March

TABLE 4.2-3
PROJECT IMPLEMENTATION SCHEDULE
IN PREPARATION FOR FINANCIAL CLOSE OF JUNE 1996

STEPS	ACTIONS REQUIRED	RESP.	SCHEDULE
	1. Appointment of Key Developer Representatives 2. Appointment of Kuban GRES Executives: General Director, Finance Director, Construction Manager, Chief Engineer, Procurement Manager 3. Orientation of Corporate Officers & Executives 4. Selection of Consultants/Lawyers as Required		1996
4. Approve Budgets	A. Project Expenditures & Schedules* 1. Revision & Establishment of Estimated Project Schedules as Required, with Review by World Bank 2. Further Specification of Expenditures & Budgets if Necessary B. Confirm Financing Plan** 1. Confirmation of Equity Commitments 2. Confirmation of Debt Existing/New Lender Commitments C. Develop Tariffs** 1. Develop Preliminary Actual Tariff Estimates* 2. Update Tariff Calculation, if Necessary, Based on Revised Estimates for Submission to Purchaser & FEC**	Primary Resp. Kuban GRES & Shareholders Secondary Resp. Purchaser (for Approval of Tariff Calculations)	March 1996 April 1996 April 1996
5. Develop & Execute Project Agreements		Primary Resp. Kuban GRES	May 1996
- Power/Heat Purchase (Between Kuban GRES & Purchaser)	A. Reach Agreement on Principles of Contract* 1. Development of Initial Proposed Principles by Working Committee & Kuban GRES Development Team 2. Coordination with Shareholders, FEC, Purchaser, & World Bank 3. Review by Russian & Western Legal Experts as Required 4. Final Approval of Principles by All Parties B. Have Draft Agreement Initialed by All Parties**	Primary Resp. Kuban GRES Secondary Resp. Purchaser, FEC, World Bank	March 1996 April 1996

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TABLE 4.2-3
PROJECT IMPLEMENTATION SCHEDULE
IN PREPARATION FOR FINANCIAL CLOSE OF JUNE 1996

STEPS	ACTIONS REQUIRED	RESP.	SCHEDULE
	1. Development of Full Draft of Document with Involvement of Western Legal Firm 2. Review by All Parties & Revision of Document 3. Initialing of Full Text of Agreement C. Finalize & Execute Agreement*** 1. Final Review of Documents by Parties and Minor Adjustments 2. Execution of Agreement		 May 1996
- Fuel Supply (Between Kuban GRES & Gasprom)	A. Reach Agreement on Principles of Contract* 1. Development of Initial Proposed Principles by Working Committee and Kuban GRES Development Team 2. Coordination with Shareholders, Gasprom, & World Bank 3. Review by Russian &Western Legal Experts as Required 4. Final Approval of Principles by All Parties B. Have Draft Agreement Initialed by All Parties** 1. Development of Full Draft of Document with Involvement of Western Legal Firm 2. Review by All Parties & Revision of Document 3. Initialing of Full Text of Agreement C. Finalize & Execute Agreement*** 1. Final Review of Documents by Parties and Minor Adjustments 2. Execution of Agreement	<u>Primary Resp.</u> Kuban GRES <u>Secondary Resp.</u> Gasprom, World Bank	March 1996 April 1996 May 1996
- Implementation Agreement (Between Kuban GRES & Government)	A. Reach Agreement on Principles of Contract* 1. Development of Initial Proposed Principles by Working Committee and Kuban GRES Development Team 2. Coordination with Shareholders, Government, & World Bank 3. Review by Russian &Western Legal Experts as Required 4. World Bank to Obtain Notification from Government for Loan	<u>Primary Resp.</u> Kuban GRES <u>Secondary Resp.</u> World Bank (for Obtaining	March 1996

TABLE 4.2-3
PROJECT IMPLEMENTATION SCHEDULE
IN PREPARATION FOR FINANCIAL CLOSE OF JUNE 1996

STEPS	ACTIONS REQUIRED	RESP.	SCHEDULE
	Guarantee/On-Lending Arrangement with Corresponding Terms Included in the Implementation Agreement (See Note) 5. Final Approval of Principles by All Parties	Government Notification on Loan Guarantee Approach),	
	B. Have Draft Agreement Initialed by All Parties** 1. Development of Full Draft of Document with Involvement of Western Legal Firm 2. World Bank to Negotiate Loan or Guarantee Arrangement with Government 3. Review by All Parties & Revision of Document 4. Initialing of Full Text of Agreement	Government	April 1996
	C. Finalize & Execute Agreement*** 1. Final Review of Documents by Parties and Minor Adjustments 2. Execution of Agreement		May 1996
- Insurance & Other	A. Develop Insurance Plan* 1. Identify Insurance Requirements 2. Develop Plan & Budget for Meeting Requirements 3. Obtain Preliminary Commitments	Kuban GRES	March 1996
	B. Obtain Final Commitments*** 1. Finalize Budgets 2. Execute Agreements		May 1996
- Project or Loan Agreement (Between Kuban GRES & World Bank)	A. Finalize Prior to Application to Board** 1. World Bank to Obtain Government Notification on Guarantee/On-Lending Approach (See Note) 2. Review of Project Loan or Agreement Provided by World Bank** 3. Coordination with Shareholders, Government** 4. Finalization of Agreement**	Kuban GRES & World Bank	April 1996
	B. Execution of Agreement		June 1996

TABLE 4.2-3
PROJECT IMPLEMENTATION SCHEDULE
IN PREPARATION FOR FINANCIAL CLOSE OF JUNE 1996

STEPS	ACTIONS REQUIRED	RESP.	SCHEDULE
6. Bid & Tender Documents	A. Develop Documents in Final Form 1. Preparation of Gas Turbine Package and Other Tender Packages (Steam Turbine, Control Systems, Electrical Equipment, Chemical & Water Treatment, Switchyard) 2. Review by Consultant & Revisions to Document 3. Finalization with World Bank	Kuban GRES & World Bank	March/April '96
	B. Bid Consulting Contract 1. Invitation for Bids 2. Pre-Bid Meeting 3. Technical and Economic Review of Bids 4. Contract Award with World Bank Review 5. Contract Negotiation		May-June '96
	C. Bid Gas Turbine (& Associated Equipment) & Construction Package 1. Invitation for Bids 2. Pre-Bid Meeting 3. Technical and Economic Review of Bids 4. Contract Award with Consultant/World Bank Review 5. Contract Negotiation		May-June '96
7. Government Loan Guarantee (Between World Bank & Government)	A. Negotiate Prior to Application to Board** 1. Notification of Government Decision Regarding Loan Guarantee vs. On-Lending Approach (See Note)* 2. Negotiation** B. Maintain Contact with Government to Expedite Approval	<u>Primary Resp.</u> World Bank <u>Secondary Resp.</u> Kuban GRES, Government	April 1996 March 1996 April 1996 Ongoing
8. Obtain World Bank Board Approval	A. Submit Staff Appraisal Report, Business Plan, Equity Commitment & Executed Project Agreements Package***	Kuban GRES & World Bank	May 1996

TABLE 4.2-3
PROJECT IMPLEMENTATION SCHEDULE
IN PREPARATION FOR FINANCIAL CLOSE OF JUNE 1996

STEPS	ACTIONS REQUIRED	RESP.	SCHEDULE
(Financial Close)	B. Review of Annexes to Project or Loan Agreement*** C. Loan Negotiation in Washington*** D. Government Approval*** E. Board Approval/Financial Close F. First Draw-Down		May 1996 May 1996 May 1996 June 1996

* Actions Required by World Bank Prior to Appraisal Mission (End of March 1996)
** Actions Required by World Bank Prior to Loan Negotiation (Mid-Late April 1996)
*** Actions Required by World Bank Prior to Financial Close/Board Approval (May/June 1996)

Note: If Government Chooses to Become the Primary Borrower from World Bank, the World Bank Would Enter into a <u>Project Agreement</u> with Kuban GRES, Which Would Enter into an <u>On-Lending</u> with the Government. If the Government Chooses to Only Guarantee the World Bank Loan, a <u>Loan Agreement</u> Between the World Bank and Kuban GRES Would be Executed. The <u>Implementation Agreement</u> Between Kuban GRES and the Government Would Also Provide for Repayment of the Loan by Kuban GRES.

B) CONSTRUCTION STAGE			
1. Issue Tender Documents & Award Bids	• Award Bids • Negotiate Contracts	Kuban GRES or Representative	Sept-Dec 1996 See Chapter 2
2. Establish Corporate Staffing & Management Organization	• Develop & Define Project Procedures & Systems • Staff Project Organization • Staff First Line Management • Establish Organizational Budgets • Implement Management Training for First Line Supervisors	Kuban GRES	July-Sept 1996 July-Sept 1996 July-Sept 1996 July-Sept 1996 July-Sept 1996

TABLE 4.2-3
PROJECT IMPLEMENTATION SCHEDULE
IN PREPARATION FOR FINANCIAL CLOSE OF JUNE 1996

STEPS	ACTIONS REQUIRED	RESP.	SCHEDULE
3. Install and Implement Management Information Systems	• Construction • Financial Performance • Plant Operations	Kuban GRES & Contactors	Sept-Dec '96 Sept-Dec '96 December 1999
4. Implement Staff Training	• Safety, MIS, Inventory Training • Operations & Maintenance Training	Kuban GRES Contractors	August-Dec '96 December '96-'99
5. Complete Construction	• Testing • "Completion Documents"	Kuban GRES & Contractor	See Schedule in Chapter 2
C) OPERATIONS STAGE			
1. Transition to Plant Operations Organization	• MIS • Reporting • Roles & Responsibilities	Kuban GRES	June-December 1999

4.2.15 Training Program

The training schedule specific for project construction and start-up will be driven by the detailed project schedule - similar to the one indicated in Chapter 2 of this report. For Example, the training for plant operators and maintenance personnel will be scheduled to phase in as the units are installed and tested. In addition, such training will be a specific requirement in the various procurement contracts.

Prior to plant startup, and before staffing is in place, programs must be established to provide the necessary training to all operating ,maintenance, technical, and clerical employees.

Detailed training programs must be developed to insure all members of the various crafts are tested to be competent in their respective work areas. These should include:

- Operator Training
- Maintenance Training
  - Electrical
  - Mechanical
  - Welding
  - Instruments & Controls
- Chemistry
- Equipment Operators
- Industrial Safety
- Management Information Systems
- Inventory Control
- Environmental Control
- Fuel Handling

Training facilities should be installed at an early stage in construction to provide for adequate training time of personnel prior to startup. The training facilities should include:

- Classrooms
- Operations simulator
- Welding training and testing facilities
- Chemical laboratory*
- Machine shop*
- Electrical shop*
- Instrument and controls shop*

*Chemical laboratory, machine shop, electric shop, and instrument shop could be the working shops constructed for the ongoing operations and maintenance of the facility.

The contract for the plant should contain a provision for the equipment supplier(s) to develop the training programs, and provide all training for the initial staff members.

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Subsequent to the start of operations, ongoing refresher and re-qualification training should be provided to all members of the staff. This program could also be designed by the equipment supplier(s) as a part of the construction contract.

4.3 Project Agreements

Principles of the key project agreements have been developed as recommendations, to reflect the project structure outlined in Section 4.1, based on the risk strategy developed in Section 3.4. Included in the appendices to this report are the following:

> **Appendix C: Principles of the Shareholders Agreement,** between the shareholders of the project company Kuban GRES,
>
> **Appendix D: Principles of the Power Purchase Agreement,** between Kuban GRES and RAO EES Rossii,
>
> **Appendix E: Principles of the Implementation Agreement,** between the Government of the Russian Federation and Kuban GRES,
>
> **Appendix F: Principles of the Heat Purchase Agreement,** between the Administration of the Mostovskoy Region and Kuban GRES,
>
> **Appendix G: Principles of the Fuel Supply Agreement,** between Kuban GRES and RAO Gasprom

These agreements have been proposed by consultants of Kuban GRES, and have not yet been agreed upon among the parties. Joint committees have been initiated to evaluate the proposed principles of agreements and develop approaches that meet the requirements of financiers and realities of the Russian power sector.

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4.4 Review of KubanEnergo Operations

4.4.1 KubanEnergo Profile

AO (joint stock company) KubanEnergo is the main electric utility serving the Krasnodar administrative region (Krai). It is the only integrated generation, transmission and distribution utility in the Krai. Several industrial customers have independent generation units that sell excess generation tothe KubanEnergo grid, and there are 25 municipal electric utilities (power resellers) that only operate municpal distribution grids to serve residential customers in the main cities and towns in the Krai.

KubanEne:go serves residential customers directly in the town of Sochi and all rural areas. There are 1 million residential customer in the Krai. KubanEnergo also serves 10,050 non-residential consumers in Krasnodar Krai. Table 4.4-1 provides a consumption profile of the major consumer groups of the utility.

Table 4.4-1
KubaneEnergo Consumer Profile
(Estimated 3rd Quarter 1995)

Consumer Group	Consumption (GWh)	Percent of Total
Large Industrial Consumers (with over 750 KV Capacity)	648.88	25.7%
Industrial and Similar Consumers (with less than 750 KV Capacity)		
Regular Industrial	225.65	8.9%
Railway	111.39	4.4%
Urban Transport	26.87	1.0%
Non-Industrial	370.58	14.7%
Agricultural Consumers		
	481.69	19.0%
Residential Consumers (Mostly Through Municipalities)		
Urban	311.74	12.3%
Rural	349.87	13.8%

Source: KubanEnergo

KubanEnergo is in deficit situation as Table 4.4-2 below indicates. In winter times, the utility sheds 150 MW of load because it cannot meet requirements through local generation or through imports. Industry and population suffer periodic brown-outs and black-outs.

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Table 4.4-2

KubanEnergo Generation Profile
(Estimated 3rd Quarter 1995)

Source	Power (GWh)	Heat (1000 GCal)
1. Net Utility Generation	1,296	148
Thermal Plant	1,205	148
Hydro Plants	90	0
2. Purchased Power	1,602	0
From Independent Producers	11	0
From the Wholesale Market (RAO)	1,591	0
3. Losses		
System Losses	225	0
4. Power Exports		
Exports to Wholesale Market	0	0
5. Total Supply to Consumers	2,673	148

Source: KubanEnergo

KubanEnergo's dependence on imported power is constant throughout the year. Its peak demand is during the winter period, and its power imports rise correspondingly between November and February, as shown in Table 4.4-3:

Table 4.4-3
Seasonal Generation Profile
(GWh)

Period	Power Imports from RAO	Purchases from Independents	Utility Generation
July 1994	562	5	912
August 1994	583	6	921
September 1994	527	8	899
October 1994	629	11	942
November 1994	736	10	1123
December 1994	870	5	1292
January 1995	795	3	1232
February 1995	730	3	1143
March 1995	726	6	1090
April 1995	619	5	1014
May 1995	519	8	951
June 1995	508	3	892
July 1995	528	3	902

Source: KubanEnergo

AO KubanEnergo consumes both natural gas and mazout (fuel oil #6) for the Krasnodar Combined Heat and Power (CHP) plant. Table 4.4-4 provides the reference fuel consumption profile for the plant.

Table 4.4-4
Reference Fuel Consumption Profile
(Estimated for 3rd Quarter 1995)

Reference Fuel Consumption	Consumption Amount
1. Electricity Production	
Grams/KWh	373.2
Thousand Tonnes	449.9
2. Heat	
KG/GCal	171.2
Thousand Tonnes	25.3
3. Total	
Thousand Tonnes	475.2

Source: KubanEnergo

The type of fuel consumed at the Krasnodar CHP plant varies seasonally on the basis of availability of fuel, prices, and environmental impact. Table 4.4-5 provides a the fuel consumption profile during the first six months of 1995.

Table 4.4-5
Fuel Consumption and Prices

Period	Gas Cons. (m^3)	Gas Prices (R/1000 m^3)	Mazout Cons. (tonnes)	Mazout Prices (per 1000 tonne)
January 1995	176,767	97.02	6,521	100.80
February 1995	157,492	96.06	2,314	65.54
March 1995	142,194	148.81	16,162	155.42
April 1995	132,233	148.48	547	209.99
May 1995	128,800	188.68	1,819	217.26
June 1995	131,965	216.54	1,824	207.45

Source: KubanEnergo

4.4.2 Organization of KubanEnergo, Personnel Issues

The organization of KubanEnergo has a total of 26 positions reporting directly to the General Director. The group is referred to as the Board of Administration of AO KubanEnergo. Five of these positions form a staff group referred to as the Executive Administration. The remaining 21 positions are Directors of operating organizations

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referred to as Branches. The members of Executive Administration are considered to be more influential or powerful.

The organization consists of the following positions:

General Director, who is Chairman of Board of Directors, Chairman of Board of Administration, & Chairman of Board of Executive Administration.

Board of Administration:
- General Director, Chairman**
  - Chief Engineer**
  - Director General Issues**
  - Director for Economy**
  - Director for Capital Construction**
  - Director for Commercial Issues**
  - Chief Engineer, Krasnodar Heat & Power Plant*
  - Director, Krasnodar Electric Grid*
  - Director, Armavir Electric Grid*
  - Director, Adygeya Electric Grid*
  - Director, Labinsk Electric Grid*
  - Director, Leningrad Electric Grid*
  - Director, Slovyansk Electric Grid*
  - Director, Sochi Electric Grid*
  - Director, Timashevsk Electric Grid*
  - Director, Tikhoretisk Electric Grid*
  - Director, Ust-Labinsk Electric Grid*
  - Director, Southwest Electric Grid*
  - Director, Special Repairs*
  - Director, Repairs and Fitting*
  - Director, Construction (Buildings)*
  - Director, Power Supply*
  - Director, Training Center*
  - Director, Rest Houses*
  - Director, Pioneer Camp*
  - Director, Food & Products for Employees*
  - Chairman, Board of Directors of New Power Plant*

**Board of Executive Administration of AO KubanEnergo
*Branches of AO KubanEnergo

AO KubanEnergo operates as a matrix organization. Directors of all Branches look to the functional Directors within the Board of Executive Administration for guidance and directions on all issues.

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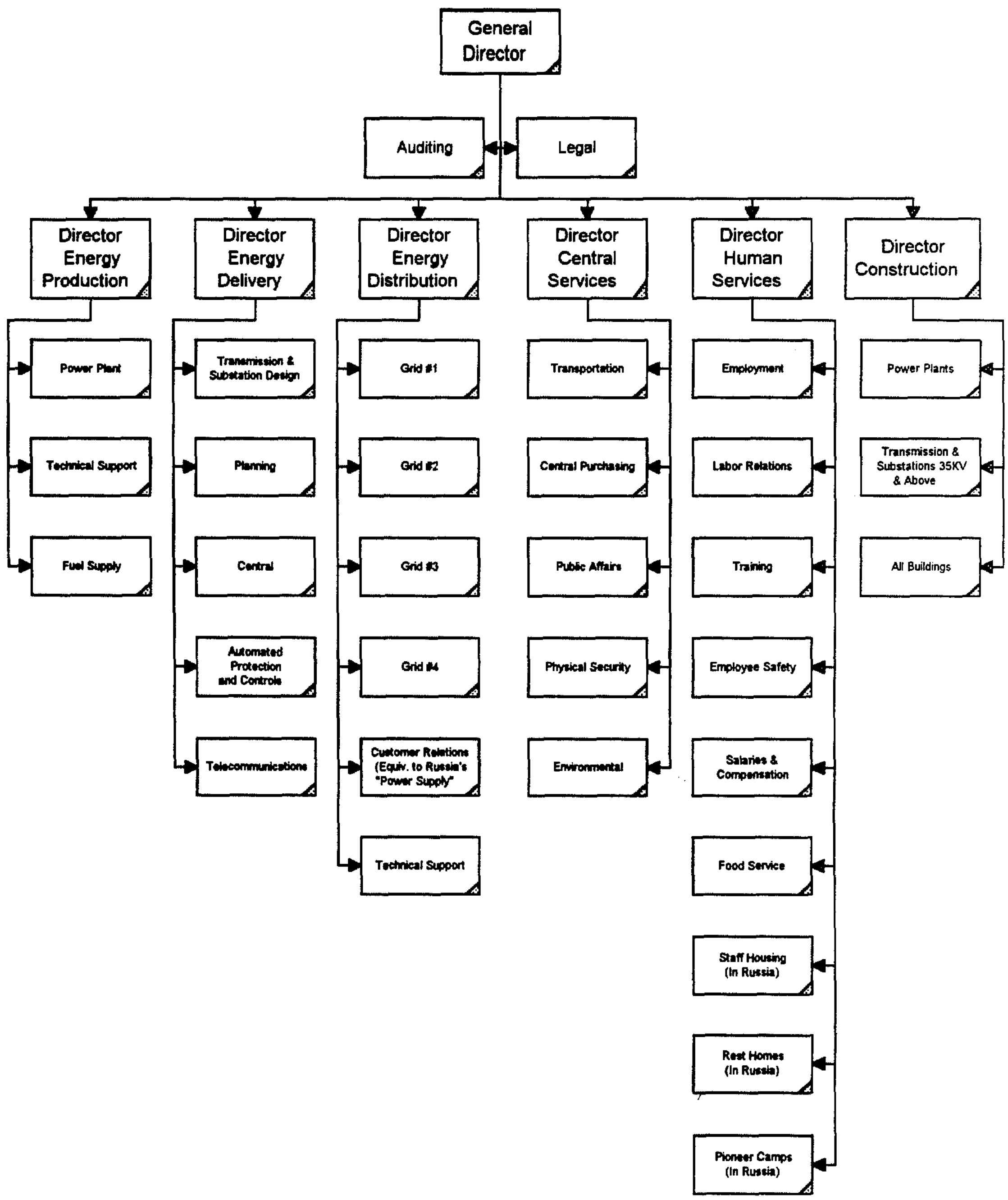
It appears cumbersome for the General Director to give direct guidance to such a large number of positions reporting to him. The General Director must rely heavily on the members of the Board of Executive Administration to manage the various functional efforts of each of the 21 Branches. Such an extensive matrix operation has proven to be inefficient within the American and European business world, where direct lines of responsibility with a limited matrix approach for managing function areas has been increasingly favored. The KubanEnergo organization does not provide for direct lines of authority and accountability, and dilutes the sense of responsibility of the managers of subordinate organizations.

Figure 4.4-1, which provides a chart of a typical electric utility organization in the USA is included for reference. It has been slightly modified to indicate typical Russian titles, and contains a few functions unique to Russia.

Figure 4.4-1

Typical USA Utility (Using Titles Common In Russia)



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4.4.3 Commercial Operations

Billing

The responsibility of billing and collections for KubanEnergo belongs with the Power Supply branch. Large and industrial customers are billed 1-2 times per month by Power Supply, which audits their meters on a monthly basis. Payments for electricity use for large customers are made through automatic transfers from their bank accounts, based on priority schedule (e.g. taxes, fuel consumption, power consumption, etc.) developed by the state. Industrial and agricultural consumers are liable for a 0.04% tax per day on unpaid balances.

Residential meters are read once a month by the residents, who pay on a monthly basis through their local post office or savings bank. Residential customers are required to pay by 10 days from the end of each month, with penalty payments of 1% per day for unpaid balances. KubanEnergo audits residential meters once per year to ensure proper reading by residents.

Until recently, most of the utility's customer information and billing systems, as well as correspondence with banks for payment transactions have been maintained manually by the Power Supply group. The use of personal computers for this function has proliferated recently, but integrated consumer information systems as found in the West are still lacking due to the relatively large investments required to implement such systems.

Non-Payments

The most significant problem affecting the utility's operations is the non-payments issue. Residential customers are the best payers. Industry, agriculture and government organizations are, according to the utility, the worst payers. More than 50% of commercial/industrial consumers are protected by the government against cut-off, and therefore have no incentive to pay. 50% of non-residential customers are non-payers according to KubanEnergo. Table 4.5-6 provides a detailed breakdown of power debts by major consumer groupings.

Table 4.5-6
Non-Payments
(as of July 14, 1995)

Industry	Debt (1000 Rubles)	% of Total Debt to Utility
1. Oil Exploration & Production	9,888,706	2.66%
2. Oil Processing	6,539,236	1.76%
3. Gas	226,407	0.06%

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4. Chemical	13,262,889	3.57%
5. Machine Building & Metal Processing	10,838,946	2.92%
6. Wood Processing and Wood & Pulp	11,089,507	2.98%
7. North-Caucasus Railway	23,871,566	6.42%
8. Government Agencies, Incl.	37,604,642	10.13%
Irrigation Systems	18,552,943	
Military-Industrial Complex	1,746,623	
9. Electric Municipalities	67,511,352	18.16%
10. Construction & Materials Manufacturing	25,431,071	6.84%
11. Agriculture	70,970,729	19.09%
12. Municipal Facilities	13,582,080	3.65%
13. Other	80,868,438	21.76%
TOTAL	371,685,569	100%

Source: KubanEnergo

The situation of non-payments seems to be improving, with a recorded decline in receivables. Typically revenues are 40% receivable, but that decreased to 13% in June. Most of the receivables are old debt, and the utility has been given authority to write-off debt that is older than 3 years.

Tariffs

The method of establishing tariffs by AO KubanEnergo allows for the margin of profit to be calculated against the total operating and maintenance costs of the company. This method does not encourage management to minimize costs consistent with efficient operations.

The tariff retail structure is established by the Regional Energy Commission, therefore AO KubanEnergo has little control at this time over the formula. The management of AO KubanEnergo should institute controls that would help to minimize negative impact on efficient operations. The company could perform additional audits of work practices throughout its operations searching for opportunities to increase efficiencies.

Procurement

Even though a service for production and technical procurement exists under the Director for Commercial Issues, departments within the company have the ability to purchase spare parts, transformers, and other materials directly from the manufacturers. There does not appear to be a centralized purchasing effort to take advantage of competitive bids, quantity discounts, or other savings typically associated with centralized purchasing. As the Russian economy improves more foreign suppliers will become available, and domestic manufactures will become more competitive. The monetary benefits of centralized purchasing will become more significant. AO KubanEnergo may find opportunities to improve efficiencies through the review its procurement practices for the potential of providing a more centralized effort within the company where the departments or divisions are requisitioning their major materials and supplies through a central purchasing department.

4.4.4 Information Management and Accounting

Accounting

The accounting activities of AO KubanEnergo are performed with a minimal amount of automation. Each of the 21 Branches has its' own accounting group, and periodically forwards the work product to the accounting office of the Director of Economy. There, all 21 reports are merged with accounting data from the various departments of the Board of Executive Administration, and a consolidated report is issued for all of AO KubanEnergo. More automation of accounting activities could reduce labor requirements, and minimize the potential for human error in data accumulation. Automation also provides for easier development of management controls tailored to the needs of each executive. Easier development leads to more requests for such controls, and can contribute to enhanced management.

Management Reporting

The management of AO KubanEnergo should review the list of reports, or management controls, that is routinely supplied to the Board of Directors and General Director. The controls should be prepared for the General Director on a monthly basis, and for the Board of Directors on a frequency coinciding with meetings. Data should be reported for the month of the report, and for the totals for year-to-date. Totals should also be compared to budgets or projections. At year end totals should be compared to the previous four years. A suggested list of reports for the General Director is below:

Financial Highlights
- Total Revenues
- Fuel Expense
- O&M Expense excluding fuel
- Earnings
- Return on Assets
- KWH Sales, totals and by class
- Average price of kwh sold by class
- Accounts Receivable
  - Totals and by class
  - 30 days delinquent
  - 60 days delinquent
  - More than 60 days delinquent

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Income Statement
Balance Sheet
Revenues
- Residential electric
- Commercial electric
- Industrial electric
- Heat
- Process steam

Fuel & Production
- Fuel cost per kwh generated
- BTU per net kwh generated
- Plant net capacity factor
- Plant equivalent availability factor
- Plant forced outage rate
- Emergency fuel inventory (hours of burn)
- Net system peak demand
- Cost of imported power per kwh
- Technical (station comsuption, transmission and distribution losses), and
- Non-Technical (unauthorized taps and unaccounted losses)

Materials & Supplies Inventory
- Sources and application of funds

Customer & Employee
- Total customers
- Customers per employee
- Customers added
  - Residential
  - Commercial
  - Industrial
  - Heat
  - Process Steam
- Total employees vs. approved positions
- Total payroll
- Average annual wage
- Cost of employee services
  - Total
  - Per employee
- Lost time accident rate
- Employee turnover rate
- Statement of Significant Events During Period

This section should contain a brief statement of unusual or significant events that occurred during the reporting period. This would include such events as an unplanned outage of a unit, and interruption to fuel supply, a serious equipment failure, a serious injury to an employee, etc..

4.4.5 Personnel Training and Development

Management Development

A program of developing managerial talent is in place. It is referred to as Management Reserves. It is a formal program that is reviewed periodically through all levels of management. Names of candidates for all management positions are documented, then reviewed through all levels of management up to and including the General Director.

The program, however, focuses a candidate on a specific position. The candidate is given certain work assignments over a period of time that are intended to prepare him or her for the position. Every five years each candidate is expected to attend a seminar or short course at a University. These courses often are more technical in nature, and do not cover general subjects of management and supervision.

If an incumbent is replaced in one of the higher levels of the organization, the new person often renames the reserves for the lower positions within his or her jurisdiction. The training of new reserves starts from the beginning, and the training of the personnel previously listed as reserves is of minimal value.

Under the present economic system employee turnover is extremely low. This condition also exists in management positions. But as Russia evolves into a free market society, and as the economy improves, worker mobility will become more prevalent. This condition will create a need for a larger supply of well prepared managerial talent. The new talent will need a broad range of managerial skills along with their technical knowledge.

The company could enhance its managerial development program by including more frequent training in the principles of management. The program could include, but not be limited to, such subjects as:

- Basic accounting
- Decision making
- Developing subordinates
- Economics
- Employee motivation
- Labor relations
- Management by objectives
- Management controls
- Negotiating
- Public speaking
- Time management
- Written communications

The development program can extend to candidates beyond those named as reserves for specific positions. Young professionals employed into the work force should be screened for their potential to be future managers. Those deemed to possess the basic attributes of managers should be entered into a structured development program extending over several years.

Financial Concepts

Because of Russia's history of state ownership and financial system, the executives, managers, and professionals of AO KubanEnergo have only recently begun to comprehend and utilize basic terms and concepts used in the world financial markets. Cost of capital and return on equity are two such subjects. Comprehension of basic financial requirements of potential investors from outside of Russia can be significantly improved to avoid impediments toward the completion of the Krasnodar Power Generation Project. Additional projects in the future will also be difficult to negotiate without a better understanding of investment principles.

The following are preliminary recommendations in this area:

1. The Board of Directors of AO KubanEnergo should provide for training in the basics of financial investments. All Board members, the General Director, Chief Engineer, Directors, planning personnel, accountants, and engineers should receive this training.

2. All management personnel, engineers, and planners should be trained in the subject of present value vs. future value of capital investments, often referred to as Engineering Economy.

3. AO KubanEnergo should invite (and encourage) the appropriate members of the local administration to participate in the above training.

4.4.6 Conclusion

In general, KubanEnergo is a well managed utility given the context of rapid restructuring in the Russian power sector, and major challenges posed by fundamental economic readjustment with the resulting difficulties in price formation and payment collections. The utility has also inherited a situation of chronic power and heat shortages, which in the short term, it can most effectively resolve through cooperation with RAO and other utilities in the region.

Although KubanEnergo will not be the direct purchaser of power from Krasnodar GRES, as discussed in Section 4.1, it is expected to play a major role both as one of the equity participants of the project, and as primary purchaser of the plant's output through the wholesale market. As a result, the utility's long term financial health and development are key considerations in development of the project.

KubanEnergo is currently at the forefront of reform and investment planning within the Russian power sector. It has been restructured and currently operates as an independent and commercially viable entity that pursues the interests of both its shareholders as well as its customers. The advanced stage of the Krasnodar GRES project is the direct result of not only its relentless pursuit of development of the Krasnodar project, but the utility's ability to adjust quickly to the reformed and uncertain environment, and effectively utilize newly-acquired skills in marketing, financing, and negotiating in a market environment. To play its designated role as the source of financial stability for Kuban GRES in the long term, the utility is therefore well positioned to implement the recommendations in this section and Section 4.5, as follows:

- Over time, automate internal control functions and establish comprehensive systems to improve both internal accountability and efficiency as well as accountability by non-paying customers,
- Work with federal and regional regulators to enhance the utility's ability to enhance collections, and restructure tariff methodologies to provide appropriate financial incentives for efficient operations, (see Section 4.5),
- Gradually reorganize utility into a more streamlined operation, through automation of certain functions and out-sourcing, where possible, and
- Further enhance skills of utility managers and regulators in areas of private sector finance and management.

4.5 Review of Regulatory Practices

4.5.1 Introduction

Tariffs in the Russian electric sector are regulated both at the federal as well as regional levels, based on enabling legislation adopted by the State Duma on March 10, 1995. RAO EES Rossii and activities related to the national wholesale market are regulated by the Federal Energy Commission (FEC). Tariffs of regional utilities (AO-Energos), which are commercialized or privatized entities in Russia's 72 regions, are regulated by the Regional Energy Commissions (RECs) in each corresponding region.

The project structuring analysis indicates that the Krasnodar GRES project would be a supplier of electric power to the wholesale market with a power purchase agreement between the project company and RAO. RAO, through the wholesale market, in turn would resell the power to AO-Energos in the North Caucasus grid, primarily to KubanEnergo. In terms of regulation, therefore, the FEC would have direct jurisdiction

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over setting and approving tariffs for the project. At the same time, the Krasnodar REC, and RECs in other regions that import power from the wholesale market, would have no direct impact on tariffs of Krasnodar GRES. Nevertheless, as the commissioning of Krasnodar GRES may increase the cost of importing power from the wholesale market for these utilities, the RECs in the region have an important role to play to ensure the ability of regional utilities to buy from the wholesale market at the higher rates.

In light of the above, the purpose of this chapter is as follows:

- *Federal Regulation:* Provide an overview of FEC practices that affect Kuban GRES,
- *Regional Regulation:* Provide an overview of Krasnodar REC affecting KubanEnergo's ability to readjust tariffs to sustain import from the wholesale market upon commissioning of Krasnodar GRES,
- *Implications for Kuban GRES:* Develop conclusions regarding the impact of regulatory practices on the Krasnodar GRES tariff and project structure,
- *Recommendations for Improvement:* Develop recommendations regarding improvements in the regulatory environment for successful implementation of Krasnodar GRES.

4.5.2 Overview of Federal Regulation

Regulation of Generators

The FEC sets tariffs for 23 fossil fuel and hydro plants, as well as 10 nuclear plants, each as an independent power producer. The non-nuclear plants, which are generally plants over 1000 MW for thermal and over 300 MW for hydro, are fully or majority owned by RAO EES Rossii, and structured as separate subsidiary companies. The nuclear plants are owned and operated by the Ministry of Atomic Energy (MinAtom).

Wholesale tariffs for generation plants are adjusted on a quarterly basis, and remain effective for a minimum of three months. At the moment, the FEC ona quarterly basis reviews the operating and other costs of each plant, and sets the plant's tariff for the upcoming quarter. Two-part tariffs are determined for generating plants: a fixed capacity charge and a variable energy charge based on utilization. The tariff usually takes into account the generation plan, fuel costs, operation and maintenance expenses, and depreciation charges, plus an add-on to these costs for profits. The profit add-on may vary among power plants. Table 4.5-1 presents the approved wholesale tariffs of the 23 independent hydro and fossil plants:

Table 4.5-1
2nd Quarter 1995 Wholesale Plant Tariffs

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Generating Plant	Wholesale Tariff (R/KWh)	Capacity Charge (Th.R/MW)	Variable Charge (R/KWh)	Heat Tariff (R/GCal)
Thermal Plants				
1. Stavropolskaya GRES*	58.33	4,185	44.27	31,437
2. Cherepetskaya GRES	141.69	7,295	101.50	59,958
3. Kostromskaya GRES	77.74	5,494	48.22	38,295
4. Ryazanskaya GRES	123.76	6,586	89.96	58,128
5. Pechorskaya GRES	65.91	6,240	37.15	40,681
6. Konakovskaya GRES	79.86	3,740	51.12	42,405
7. Permskaya GRES	64.71	6,603	37.82	37,044
8. Troitsk.'ya GRES	78.67	7,432	50.19	44,118
9. Gusinozerskaya GRES	130.82	12,710	45.94	55,748
10. Nevinnomyskaya GRES*	67.62	4,724	53.20	27,388
11. Krasnoyarskaya GRES	63.55	5,024	18.48	27,717
12. Berezovskaya GRES	237.40	9,241	35.78	33,169
13. Pskovskaya GRES	86.31	11,279	50.19	45,103
14. Kharanosrkaya GRES	-	-	-	101,287
Hydro Plants				
15. Volgogradskaya GES	8.70	4,077	0.043	-
16. Nijegorodskaya GES	12.57	3,514	0.063	-
17. Verkhnev Cascade GES	11.30	3,668	0.056	-
18. Voljskaya GES	11.85	4,880	0.059	-
19. Votkinskaya GES	8.95	2,453	0.45	-
20. Kamskaya GES	12.25	5,638	0.61	-
21. Sayano-Shushenskaya	9.50	1,987	0.47	-
22. Zeiskaya GES	26.28	6,220	0.131	-
23. Saratovskaya GES	9.80	3,90	0.49	-

** Plants in North Caucasus Region*

Power is currently sold by the fossil, hydro, and nuclear plants at the tariffs set for each facility, to the wholesale market. RAO, as the market-maker does not take title to the power, but arranges suppliers with customers of the wholesale market for payments providing for a clearinghouse function. This process ensures the levelization of tariffs of the wholesale market to the purchasers within geographic regions. Power supply agreements are executed between Central Dispatch Agency of RAO and the generating plants on an annual basis determining the plant's generation profile. Each plant is dispatched by the Central Dispatch Agency on the basis of plant availability, marginal cost, system loads, and heating needs.

As of yet, the wholesale market does not have long term power purchase contracts with generators in the country. Both RAO and the FEC, however, recognize the need for such agreements for new or refurbished projects as a prerequisite for non-utility investments in projects.

Regulation of the Wholesale Market

The bulk power market in Russia is also regulated by the FEC. This market is primarily comprised of inter-utility power transfers administered by RAO, which owns and operates high voltage transmission lines. Table 4.5-2 shows the average wholesale tariffs charged by RAO to deficit regional utilities:

Table 4.5-2
Estimated Average Wholesale RAO Tariffs to Deficit Utilities*

Utility Pool	Estimated Imports, 2nd Quarter Total (Mil KWh)	Estimated Average Tariff, 2nd Quarter (R/KWh)
1. Center (18 Utilities)	19,879	63.73
2. North-West (9 Utilities)	4,418	62.80
3. Volga Region (6 Utilities)	5,776	52.55
4. Urals (5 Utilities)	7,565	63.10
5. North Caucasus (8 Utilities)	4,174	56.21
6. Siberia (9 Utilities)	5,978	42.68
7. Far East (1 Utility)	928	28.40

* Utilities that Purchase Power from Wholesale Market or Directly from RAO Plants.
N.B.: Wholesale tariffs also vary within each pool for among utilities.

The wholesale tariffs to deficit utilities consists ofwhich is essentially a pass-through of the cost to of purchasing power from large generating plants and regional utilities with excess power. RAO does not include in this charge the cost of operating and maintaining grids, or any other mark-ups.

The service charge, on the other hand, is an additional charge applied to all consumers (mainly utilities) of the wholesale market. It is a fixed service charge paid to RAO based on each utility's total energy (capacity) demand. This service charge is adjusted on a quarterly basis and essentially reflects the cost of operating and maintaining RAO's transmission facilities, the allowed profit for RAO, and constributions to RAO's investment fund. Table 4.5-3 provides a breakdown of the components of the service charge.

Table 4.5-3
Components of the RAO Service Charge

Service Charge Component	Typical Weight
1. Investment Component	67.2%
2. Operation and Depreciation of Grids	8.0%
3. Operation of Dispatch Centers	2.0%
4. Technical Supervision Services	0.4%
5. RAO Administrative Expenses	0.7%

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6. Insurance and R&D Funds	7.0%
7. Highway Fund	2.5%
8. Federal and Local Taxes	9.9%
9. Other, Including Shareholder Dividends	2.4%

The service charge is a relatively small part of the retail tariff, generally less than 10%. The FEC ensures that this component covers costs for maintaining the wholesale market, and allocates the majority of the charge to contributions towards an investment fund. This allocation is based on annual investment plans developed by RAO and approved by the FEC. In the event of stabilization and normal operation of the wholesale market, therefore, the service charge would be adequate to ensure the financial health of RAO, and the availability of resources for development of the power sector as required. However, due to the non-payments situation that has affected regional utilities, and as a result payments to RAO, actual collections have fallen short of required revenues, thereby affecting RAO's ability to pursue its development program for the moment.

4.5.3 Overview of Regional Utility Regulation

The Russian Law on Energy Price Regulation of March 1995 establishes the Regional Energy Commissions (RECs) of Russia as entities that are relatively independent of the FEC in setting retail (consumer) tariffs for heat and power. The FEC's jurisdiction in this area is limited to the resolution of disputes between the RECs, Energos and consumers.

The established methodology for setting tariffs for regional utility is also based on the "operating cost plus profit" approach. Each REC independently determines the target profit level, based on forecasted expenditures and submitted estimates. This profit level ison average 25%.

On a quarterly basis, each Energo submits to the REC a "business plan" for the following quarter, outlining operating costs with proposed tariffs based on the allowed profit. Depending on the REC, many utilities are allowed to include in their quarterly plans a forecast of inflated fuel and operating costs, in order to recover actual costs. As tariffs can only be set on a quarterly basis, if fuel and other costs increase more rapidly than forecasted figures, Energos are exposed to the differential during an entire quarter.

Upon establishment of an average tariff for consumers, the Energo also submits proposed rates for various classes of consumers established. Power and heat prices for the different consumer classes are approved by the REC, and the level of cross subsidies among these classes varies by region. In general, industrial customers pay most for energy, subsidizing agricultural and residential consumers. Nevertheless, there has been an established trend recently to move towards elimination of cross-subsidies. Many utilities pland to raise agricultural and residential tariffs to equal cost of generation.

Regulation of KubanEnergo

KubanEnergo is regulated on an "operating cost plus profit" basis, with an estimated profit target of 15%. The utility submits its proposed tariffs on a quarterly basis to the Krasnodar REC. Table 4.5-4 presents KubanEnergo's proposed tariffs for the 3rd quarter of 1995:

Table 4.5-4
Tariff Breakdown by Consumer Group

Consumer Group	2nd Quarter 1995 Tariff	3rd Quarter Proposed Tariff
Large Industrial Consumers (with over 750 KV Capacity)		
Capacity Charge (Rubles/KW per year)	512.84	746.83
Energy Charge (Rubles per KWh)	95.22	208.39
Industrial and Similar Consumers (with less than 750 KV Capacity)		
Regular Industrial (Rubles per KWh)	131.17	208.39
Railway (Rubles per KWh)	133.54	208.39
Urban Transport (Rubles per KWh)	133.79	208.39
Non-Industrial (Rubles per KWh)	127.00	208.39
Agricultural Consumers		
(Rubles per KWh)	83.92	146.72
Residential Consumers		
Urban (Rubles per KWh)	22.71	49.79
Rural (Rubles per KWh)	15.12	35.56
Wholesale to Municipalities		
(Rubles per KWh)	61.59	93.7

Table 4.5.4 illustrates the disparity between industrial and agriculatural/residential rates in Russia. However, KubanEnergo and the REC have stated that their goal is to gradually move towards a tariff system that reflects the cost of service for each consumer group. In the short term, the REC has agreed to raise agricultural tariffs to equal generation costs plus 5%.

Table 4.5-5 summarizes KubanEnergo's methodology for arriving at its proposed average tariff level. The proposed "business plan" submitted to the REC includes material substantiating the estimated generation costs for the upcoming quarter, the required profit to meet shareholder earnings targets and other social responsibilities, and the generation plan.

Table 4.5-5
Summary of Tariff-Setting Methodology
(3rd Quarter 1995 Proposed)

Component	Unit	Amount
1. Generation Cost		

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Power	1000 Rubles	415,209,398
Heat	1000 Rubles	7,071,367
Total	1000 Rubles	422,280,765
2. Required Profit		
Capital Investments	1000 Rubles	13,112,655
Production Development	1000 Rubles	2,887,345
Social Development	1000 Rubles	2,000,000
Personnel Promotion	1000 Rubles	250,000
Dividends to Shareholders	1000 Rubles	1,500,000
Other	1000 Rubles	1,000,000
Taxes on Profits	1000 Rubles	27,902,855
Total	1000 Rubles	48,652,855
4. Sales		
Power	GWh	2,673
Heat	1000 GCal	148
5. Average Wholesale Tariff		
Power	Rubles/KWh	172.10
Heat	Rubles/GCal	54,946

The tariff setting process is rather interactive, with KubanEnergo economists and members of the advisory committee of the Administration's Price Committee working closely to analyze the reasonableness of figures submitted and forecasts made. Upon reaching an agreement, the REC reviews and approves tariff recommendations made, setting tariff levels for the entire following quarter. The utility's supporting documentation consists of a set of standardized forms that substantiate each of the components in Table 4.5-5. Table 4.5-6 below provides an example the utility's 2nd quarter 1995 plans that describe its "generating costs." These costs in reality include all operating costs, such as generation and distribution costs, depreciation, and purchased power. The REC's willingness to adjust KubanEnergo's tariffs in a timely manner to reflect increases in cost of power purchases is an important consideration from the perspective of developing Kuban GRES.

Table 4.5-6
Methodology for Estimating Operating Costs for Tariff Setting
(3rd Quarter 1995 Plan)

Cost Components	Power (1000 Rubles)	Heat (1000 Rubles)
1. Fuel	99,852,864	5,623,769
2. Water	1,122,000	82,500
3. Main Wages for Operating Personnel	10,000,000	45,000
4. Additional Wages for Operting Personnel	1,000,000	5,000
5. Payments for Social Insurance Deducted from Wages	4,290,000	19,500

6. O&M Materials, Supplies and Equipment Costs, Incl.	44,550,000	379,500
a) depreciation charges	*16,400,000*	*43,388*
b) payments to the repair fund	*0*	*0*
c) O&M expenses for municipalities	*684,000*	*0*
7. Start-up Costs	300,000	0
8. Shop Costs	8,745,000	48,000
9. Joint Costs, Incl.	101,894,334	868,098
a) RAO service charge	*31,408,651*	*0*
b) payments to insurance fund	*4,608,015*	*81,321*
c) payments to R&D fund	*5,795,606*	*98,494*
d) payments to investment fund	*18,432,062*	*325,283*
10. Purchased Power	143,455,200	0
11. Total Generation Costs, Incl.	415,209,398	7,071,367
a) power plants	*116,194,894*	*6,566,269*
b) grids	*66,800,813*	*0*
NET SUPPLY	2,673 GWh	148,000 GCal
COST PER GENERATION UNIT	155.3 R/Kwh	37,998 R/GCal

Despite this approach to tariff setting, KubanEnergo's cash revenues have been far short of budgeted levels due to the non-payments situation. Therefore, the utility has had to frequently deplete its cash resources, often at the expense of its shareholder earnings, to meet operating expense requirements. As a result, utility management and shareholders have to date not become accustomed to the concept of return on invested capital.

With regards to investment resources, KubanEnergo includes in its proposed tariff an investment fund component to finance future investment projects. For 1995, however, KubanEnergo has reduced its planned contributions in comparison to previous years to the investment fund awaiting further guidelines about required contribution levels from RAO and the FEC.

Utility tariffs for power and heat, once set, remain in effect for a minimum of one quarter. The REC is not empowered, for example, to approve flexible tariffs that can be automatically adjusted by the utility in case of rises in operating costs. As a result, the REC allows KubanEnergo to submit new tariff proposals that take into account the impact of forecasted inflation and fuel price increases on the next quarter's operating costs. Table 4.5-7 shows KubanEnergo's proposed inflation indexes for the 3rd Quarter of 1995. This forecast is generally based on the actual inflation indexes observed in the previous quarter. At the end of a given quarter, however, the utility's shortfall from the allowed profit is not retroactively compensated for, and the utility's retained earnings are commonly exposed to actual cost increases beyond those forecast. As a result, according to KubanEnergo, its profitability has been closer to 10% and not the target 15%.

Table 4.5-7
Forecasting of Inflation Impact on Cost Items

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(3rd Quarter 1995 Proposed)

Power Generation Cost Component	Inflation Index
1. Generation Services	1.561
2. Raw Materials, Major Materials	1.275
3. Auxiliary Materials	1.424
4. Imported Fuel	1.44
5. Imported Power	1.486
6. Salaries	1.003
7. Payments for Social Needs, Incl.	
Social Insurance	.334
Employment Fund	.02
Medical Insurance	.036
8. Fixed Asset Depreciation	1
9. Other Costs, Incl.	
Repairs Fund	0
RAO Service Charge	1.386
Interest Payments	1.067
Payments for Emissions	1.431
Other	1.746
10. Purchased Power	3.739
11. Total Generation Costs	2.062

The Krasnodar REC seems to be one of the more progressive in the North Caucasus region, and has been cooperative with KubanEnergo in approving higher tariff levels, planning new investment projects, and addressing issues of concern to the sector. As a benchmark, Table 4.5-8 presents the various retail tariff levels of the distribution utilities in the North Caucasus grid:

Table 4.5-8
Power Tariffs of North Caucasus Utilities
(Rubles/KWh, Approved June 1995)

Utility	Average Tariff	Industrial Tariff	Agricultural Tariff	Urban Population	Rural Population
DagEnergo	55.2	110.6	60	60.0	42.0
KabbalkEnergo	121.7	170.3	135.0	92.0	64.0
KalmEnergo	107.8	138.3	125.3	80.0	56.0
KubanEnergo	*130.0*	*208.4*	*146.7*	*49.8*	*35.6*
RostovEnergo	113.1	154.5	93.0	50.0	35.0
SevkavkazEnergo	83.5	106.1	83.5	56.0	39.0
StavropolEnergo	147.0	209.1	119.75	60.0	42.0
KarachaevoCherkess	117.9	140.4	113.0	72.0	50.0

KubanEnergo's average approved tariff as well as industrial and agricultural tariffs are relatively high compared to other utilities in the North Caucasus region. Residential tariffs, on the other hand, are near the lowest in the region.

4.5.4 Implications and Conclusions for Krasnodar GRES

Federal Regulation

The current approach to regulating RAO and the Russian wholesale market has been designed to maintain an effective, reliable and viable power sector during a period of profound economic restructuring and turmoil. This approach has resulted in the restructuring, commercialization and partial privatization of the sector while maintaining the advantages of having a vast and integrated power system. Both RAO and the FEC recognize, however, that regulatory policies need to evolve further to enable the future development of the sector through large-scale investments of capital.

In general, the FEC should promulgate a comprehensive set of guidelines that encourage the development and financing of private power projects and remove current uncertainties in the institutional environment with regards to private power. These guidelines would include a general framework of concessions, guarantees, acceptable contracts, and approval procedures.

For the short term, key areas have been identified that require further regulatory reform to enable the implementation of Krasnodar GRES and other large-scale investment projects. These issues have been discussed with both RAO and FEC representatives, who have generally expressed agreement with the recommendations outlined below.

1) Tariff Structure

The current "cost plus profit" approach to tariff setting ensures the viability and continued operation of existing plants. Furthermore, to increase generating efficiencies, it is planned that, over time, the energy charge component of independent generating facilities will become deregulated, and determined through real-time competition of plants on the wholesale market.

To accomodate Krasnodar GRES and other similar large investment projects, however, certain adjustments need to be made to approved tariff structures. As proposed in Section 4.1, tariffs for Krasnodar GRES and similar plants should ensure efficiency incentives and competitiveness of the plant, while also ensuring the target equity returns. This can be achieved by promoting competition among plants on the basis of their marginal cost (energy charge), while allowing capacity payments that essentially ensure debt service coverage as well as return on invested equity, for plants that meet operating requirements.

2) Terms of Agreements

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Power purchase agreements between generators and RAO are currently renegotiated on an annual basis. Longer term agreements, covering periods of 20-30 years would be required for the implementation of new projects with timely adjustments of tariffs to fully cover cost increases.

3) Uncertainties in Sector Restructuring

The Russian power sector has undergone significant restructuring in recent years, without affecting the sector's effectiveness in meeting customer needs in power and heat. Reforms undertaken in this sector, and significant achievements to date in establishing independent and professional regulatory structures, are unparalleled throughout much of the former Soviet Union. However, while much change has taken place in a short period of time, additional significant changes, such as restructuring of the FEC and transitioning of IPS to a competitive wholesale market, remain on the horizon. This process, therefore, continues to present various uncertainties in planning for private sector development of large, capital-intensive projects, in particular for projects such as Krasnodar GRES which involve outside capital.

The development of new projects can be safeguarded from uncertainties in the future evolution and regulation of the power sector. For the pioneering new projects such as Krasnodar GRES, it is recommended that certain government assurances be provided to the project company to demonstrate the government's and the regulators' commitment to developing the sector and safeguarding investor interests. One such assurance could be a long term agreement provided by the government to approve project and tariff structures as outlined for Krasnodar GRES, ensuring a timely, transparent and reasonable review and adjustments of plant tariffs as required. Certain assurances can also be given to safeguard projects against the adverse impact of direct government intervention in the power sector, including restructuring, divestiture, and changes of law.

Regional Regulation

As stated above, the regulatory environment in Krasnodar does not directly impact the viability of Krasnodar GRES, but in the long term will impact the financial health of KubanEnergo and its ability to absorb power generated by the project. In general, the regulatory environment of KubanEnergo is favorable both for the utility and for Kuban GRES. The utility is allowed to recover, although with some lag as explained above, quarterly cost increases resulting from inflation, higher fuel prices, and increasing cost of purchasing power from the wholesale market. As power from Krasnodar GRES will be supplied to KubanEnergo through RAO, the current tariff adjustment mechanism would provide the utility with the flexibility to recover incremental increases in the cost of importing this power.

Despite the generally favorable regulatory approach, opportunities exist to enhance KubanEnergo's commercial viability and improve its ability to plan for future investment projects through regulatory reform. Several issues concerning the long term viability and regulation of Kubanenergo have been identified:

1) Non-Payments

The primary constraint to KubanEnergo's healthy development is the non-payments situation prevailing in the region and throughout Russia. This may only be a short term concern, as utility and regulatory officials indicate, but regulators have a role in more effectively addressing the issue to achieve a healthy power sector and enable economic growth.

KubanEnergo has indicated that 50% of its non-residential customers are protected from power cut-offs by the state. Some of the worst non-payers, according to the utility, are government institutions. These customers, therefore, have little or no incentives to make payments to the utility for energy consumed. While the institution of strict penalties for non-paying organizations is necessary, the ability of the utility to interrupt service to these organizations should be expanded and evercised.

2) Incentives for Efficiency Improvement and Investment

The current tariff methodology, which has been promulgated throughout the Russian power sector, is based on allowing a mark-up to the regulated company's operating costs. This is an approach that ensures fair profits to the utility, based on the level of earnings that regulators deem appropriate. At the same time, a more traditional rate of return on assets mechanism may not be as effective because most utilities have inherited assets from their predecessor organizations at low book values, and the book value of these assets continues to erode significantly despite periodic revluations.

The main concern with the existing tariff is that it does not provide the utility with incentives to maximize efficiency, as its profits increase with operating costs. The primary efficiency incentives stem from the REC's oversight of utility operations, which may not always ensure optimal decisions. The current tariff structure also provides little or no incentives to the utility to make new investments, as returns are not based on levels of investment but on operating costs. In theory, therefore, if the utility is confronted with two options: a) to invest in a low-cost and inefficient plant, and b) to invest in a high-cost but efficient plant, it has financial incentives to choose the former option because it can benefit from the higher operating costs of the plant while avoiding higher investment outlays up-front. It is not clear, however, if this is true in practice as few new investments have been made in the power sector.

Current tariffs, therefore, may be at an appropriate level, but they do not necessarily provide the right incentives for development. Regulators should recognize the defficiencies of the current system and view it as a temporary one. In the longer term the regulatory environment should provide the utility's shareholders the financial incentives to invest in a socially optimal manner.

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3) Concept of Shareholder Returns

The REC's current approach to regulation is based on its objective to protect rate-payers from monopolistic abuse by the utility while allowing the utility to be "profitable." The concept of ensuring a fair return on investment for the utility's shareholders (be it RAO or individual shareholders in the future) that is competive with other investment options available to them has not taken root yet among regulators. The current approach may be adequate as a temporary method to deal with short term crises during the transformation stage of the sector. In the long term, however, it would not attract new investments for the development of the power sector as a whole.

Regulators should develop a long term strategy for attracting and keeping investors in the power sector by establishing a system of stable and competitive returns for them. A new tariff mechanism should be instituted, over time, to ensure that target rates of return are met, while providing incentives for efficient operation of the company and new investments that meet both shareholder and rate-payer needs.

4) Role of the Investment Fund

It appears that development of the investment fund through a special-purpose component in the tariff structure is an effective method of allocating scarce resources for much needed investment and development. However, for the long term, regulators need to develop clear rulings and guidelines for the use of such funds, and the regulatory treatment and ownership of assets financed through the investment fund. This investment component should preferably be a part of the capital asset recovery component of RAO's tariff.

5) Tariff Levels

As shown in the analysis above, industrial and agricultural tariffs of KubanEnergo are higher than those of most other utilities in the region, and residential tariffs are among the lowest. Stabilization of these sectoral tariffs to more accurately reflect cost of service would therefore relieve the cross-subsidization burden currently imposed on industry and enable economic growth in the region.

5.0 PROCUREMENT PROCESS

5.1 Introduction

Under World Bank financed projects such as the proposed Krasnodar GRES project , the bank prescribes specific guidelines as to how procurement is to be handled. Principal bank conditions include: (1) Use of the bank's standard bidding documents including their terms and conditions; and (2) Invitation of International Competitive Bids from qualified entities for all equipment and plant to be financed from World Bank loan funds. Procurement for the Krasnodar GRES project will consist of several major contract packages, each administered using the two stage bid process.

A draft Invitation for Bid documents for each package has been prepared using World Bank provided documents referred to as the "Supply and Installation of Plant and Equipment" as issued June 1995. A preliminary index of the bidding document is shown in Table 5.1-1 and provides a general indication of how the Invitation is being organized. Table 5.1-2 provides a breakdown of the Technical Specifications to be included.

5.2 Two Stage Bidding Process

In accordance with the bank's instructions, the Invitation to Bid (ITB) for each package is being prepared on the basis of a two stage bidding approach. Under this approach, bids are invited first on a technical basis and no prices are submitted by the bidders. Except for prices, bids will be complete in all respects. Bidders will detail their commercial and technical offers and provide complete detail and description of their proposed approach for the respective supply and install scope. Bids will include completed data sheets, drawings, flow diagrams, experience of named equipment, schedule for the work etc. The bids will also indicate if there are proposed exceptions to any of the terms or conditions for the works.

After receipt of the first stage bids, a full evaluation of the offers will be conducted. Meetings are held with some or all of the bidders to clarify the offers, to bring to the bidders attention changes which need to be incorporated, and to advise bidders of conditions / exceptions that are unacceptable in bidder's offer.

At the end of the first stage evaluation, acceptable bidders are formally notified (by an amendment) to submit updated technical and commercial offers incorporating changes as discussed or as may be required by the owners. Bidders who submitted bids that are substantially non-responsive or do not meet the minimum qualification requirements are notified that their bid is rejected and that no further action will be taken on their offer.

Following a reasonable time period allowed for bidders to update their proposal, acceptable bidders will submit their updated technical and commercial offers. Changes, clarifications, and modifications prescribed in the amendment and during the clarification meetings should be incorporated by the bidders. As a part of this second stage submittal, bidders will submit complete pricing schedules on a single responsibility basis. Updated bids will be submitted the

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designated place in two envelopes. One envelope will be for all items except prices and the second envelope will include the price schedules. At a prescribed time, the price schedule envelope will be opened and read aloud to all bidders who chose to attend the bid opening.

After the priced bids are opened, a thorough evaluation is conducted of the bids. During this stage, bidders are expressly prohibited to contact the owners or any of the evaluation team. Bidders who may elect to try to influence the bid process could have their bid rejected. After a thorough evaluation of the bids and after all aspects of costs are considered, the low evaluated technically responsive bid is selected and such bidder is notified that their bid as updated is accepted. The notification of the acceptance then obligates the bidder to put up the performance security and to sign a contract agreement as proposed in the second stage process. Following receipt of the required security and the agreement is signed by all parties, the other bidders are advised who has been selected and the Project commences on track.

5.3 Bid Packages

The procurement will be accomplished in seven (7) bid packages, selected on the following bases:

- Packages have logical terminal points.
- Each package comprises a stand alone system or systems, so that performance criteria may be specified for each system.
- The supplier will have complete responsibility for the package and will be required to provide performance guarantees for its scope of work.
- All packages are suitable for International Competitive Bidding.
- Incentives are provided to ensure that the domestic bidders will have a fair chance.

The content of each bid package is as follows:

1. Combustion Turbine Generators (CTG) and Auxiliaries
    - Combustion turbines and generators complete with auxiliaries and piping;
    - Fuel gas supply system;
    - Fuel oil supply system;
    - Control systems for gas turbines, including an automatic process control system;
    - Bypass pipes for gas turbines complete with diffusers to connect to the heat recovery boiler;
    - Main step-up transformer for CTG;
    - Generator circuit breakers for CTG;
    - Isolated phase bus for CTG

2. Heat Recovery Steam Generators, Steam Turbine Generators (STG) and Auxiliaries

- Heat recovery steam generators complete boiler auxiliaries and piping;
- Deaerators;
- Boiler feed water system (high pressure and low pressure) complete with pumps and piping;
- Ductwork from steam generator to the main stack inlet;
- HRSG blowdown system;
- Steam turbines and generators complete with auxiliaries, steam piping (high pressure and low pressure), piping for miscellaneous auxiliary systems;
- District heating extraction steam system complete with heat exchangers, pumps, pipes, valves, heating pipe connection valves;

3. Distributed Control System (DCS)

- Overall plant control system with central unit control panel and local control panels.

4. Major Electrical Equipment

- Main step-up transformers for STGs
- Generator circuit breakers for STG
- Isolated phases buses for STG
- Medium voltage distribution system
- Low voltage unit substation
- DC Power system
- Uninterruptible power supply (UPS)
- Installation of DCS cabinets

5. Plant Auxiliaries and Facilities

- Direct air-cooled condenser with exhaust duct from steam turbine exhaust
- Main vacuum system
- District heating boilers
- Well water system
- Water pretreatment package
- Wastewater treating equipment
- Boiler chemical feed system
- Air compressor package
- Component cooling water heat exchanger
- Miscellaneous pumps
- Miscellaneous tanks
- Piping, hangers and insulation
- Fire protection system
- Heating ventilation and air conditioning systems

- Low voltage motor control centers
- 230/400 VAC distribution system
- Diesel generators
- All electric power and control cables
- All control wiring and instrumentation cables
- Lighting, alarm, grounding, communication

6. Switchyard

- 220 and 500 kV switchyards
- Associated electrical equipment
  Circuit breakers and disconnect switches
  Auto transformers
  Three-phase shunt reactor
  DC and UPS power systems

7. Civil Works

- Gas turbine & generator foundations;
- Heat recovery steam generator foundations;
- Steam turbine & generator foundations;
- Bridge crane and other lifting equipment;
- Main building, administrative building, engineering/laboratory building, other buildings complete with architectural finishes;
- Process piping support structure: foundations and installation of surface structures;
- Miscellaneous equipment foundations;
- Storage-tank foundations;
- Main stack complete with foundation;
- Roads and paving;
- Site drainage system;
- Fencing;
- Rail sidings;
- Site grading;

Table 5.1-1

KRASNODAR GRES

INDEX

INVITATION FOR BID

Section	ITEM
I	Invitation for Bids (IFB)
II	Instruction to Bidders (ITB)
III	Bid Data Sheets (BDS)
IV	General Conditions of Contract (GC)
V	Special Conditions of Contract (SC)
VI	Technical Specifications and Drawings (TS)
VII	Forms, Certificates, and Procedures (FCP) 1. Bid Form and Price Schedules 2. Bid Security Form 3. Contract Agreement Form and Appendices 4. Performance Security Form 5. Bank Guarantee Form for Advance Payment 6. Form of Completion Certificate 7. Form of Operational Acceptance Certificate 8. Change Order Procedures 9. Qualification Form
VIII	Eligibility for the Provisions of Goods, Works and Services in Bank-Financed Procurements

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Table 5.1-2

KRASNODAR GRES

TECHNICAL SPECIFICATIONS

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6.0 ENVIRONMENTAL ASSESSMENT

6.1 Introduction

In accordance with World Bank requirements, a detailed assessment of the environmetnal impact of the proposed Krasnodar GRES plant has been performed. The information required for the Environmental Assessement (EA) closely parallels the requirements of an Environmetnal Impact Assessment prepared in accordance with Russian Federation environmental regulations.

The Environmental Assessment (EA) is provided as a separate document, Volume III, of the Krasnodar Feasibility Report. A summary of the results of the EA is provided in this section.

This Environmental Assessment report was generated from data and information supplied by Krasnodar State Agricultural University (KSAU) and Russian Oil Initiatives Limited (ROIL) under the direction of Burns and Roe Environmental Services, Inc.

6.2 Project Description

The EA contains a description of the proposed project which is provided in Chapter 2 of this report.

There are several district infrastructure improvement projects that the project Ownership Group has undertaken in support of the Krasnodar GRES project. The existing Mostovskoy water treatment plant is in the final stages of expansion in anticipation of the increased need for capacity due to the construction and operation of the Krasnodar GRES facility. In addition, a potable water pipeline is being planned which will improve the reliability of the Mostovskoy potable water system. Previously completed infrastructure improvements in support of the Krasnodar GRES include asphalt and cement production facilities and housing construction for management and senior staff of the power plant.

6.3 Potential Environmental Impacts

A thorough environmental impact assessment was conducted for the Krasnodar GRES. Potential environmental impacts during construction and operation of Krasnodar GRES were evaluated based on current site conditions, previously conducted studies, and mathematical modeling. No significant negative environmental impacts are anticipated during normal construction and operating conditions. In addition, design considerations, administrative controls, and engineering controls will be implemented to reduce the likelihood of negative environmental impacts during upset conditions and accidents/acts of nature.

An analysis of potential environmental impacts can be summarized as follows:

Positive Impacts

- Additional facilities (associated with construction) shall contribute to general development of the district and will have direct and indirect positive impacts on revenues and living standards of the population.

- Electricity generated by the plant will contribute to economic, industrial, and agricultural development in the entire Krasnodar Territory and further increase employment opportunities.

- The quality and reliability of the water supply for Mostovskoy village will improve due to the commissioning of a water intake in Andryuki village associated with the project.

- The construction of housing, sports facilities, medical centers, transportation, and other facilities associated with the project will cause considerable socio-economic improvement due to increased employment opportunities and improved living standards.

- There will be no resettlement of the population.

Insignificant Impacts

- The power plant facilities will not have a negative environmental impact on the ecological system of the Caucasus biosphere reserve and will not disrupt its preservation regulations.

- Impact on surface and ground water, accounting for the mitigating measures to be taken, will be insignificant.

- Impacts on aquatic and terrestrial biota will be insignificant.

- Impacts caused by noise are not anticipated due to the noise mitigation measures to be taken.

- The proposed routings of the transmission lines are far enough away from population centers such that EMF exposure will not exceed regulatory limits.

- As no known flight paths intersect proposed transmission line routings, there will be no impact on bird migration.

- There will be no impact on general topography and land use in the area.

- Disposal of silty wastes from the process water treatment plant is considered to be an insignificant positive impact on the local population due to the agricultural benefits of land application of the silty wastes.

Minor Impacts

- Concentrations of SO_2 and NO_x in the atmosphere due to power plant emissions will increase slightly but will have an insignificant impact on air quality. The expected concentration increase will be within permissible limits.

The environmental impact assessment performed in accordance with the existing Russian Regulations for EIA shows that the proposed Krasnodar GRES project meets the environmental requirements of the legislation of the Russian Federation.

6.4 Environmental Management Plan

Kuban GRES will have a Health & Safety Department and a separate Environmental Department. The number of personnel will be based on the power plant staffing structure. Department personnel responsibilities will be assigned based on statute laws, standards and regulations and will be described in the Department Regulations and appropriate operating instructions which are currently being developed by Kuban GRES.

6.4.1 Water Management

A system of management, institutional, and engineering controls will be established at Krasnodar GRES during construction and operation to ensure that all waters discharged will conform to permitted water quality parameters.

6.4.2 Emissions Monitoring

A continuous emission monitoring system shall be installed at Krasnodar GRES to ensure that the plant is operating within permitted limits.

6.4.3 Training

Environmental training programs in the areas of air and water quality monitoring, solid waste management, noise abatement, health and safety monitoring, and operation and maintenance of environmental monitoring equipment will be conducted at the Krasnodar GRES.

6.4.4 Emergency Response

An emergency response plan with appropriate staff assignments is currently being developed by Kuban GRES.

6.4.5 Mitigation Measures

Mitigation measures presented in Chapter 8 of the EA are segregated into two categories to reflect the impacts associated with construction and operation of the proposed Krasnodar GRES.

Each phase of the project will involve specific activities which have the potential to generate environmental and socio-economic impacts. The proposed mitigation measures presented in Chapter 8 are intended to either minimize an impact or, wherever possible, to prevent the impact completely. A qualitative ranking of impacts (e.g., insignificant, moderate, severe, positive and negative) and the associated mitigation measures have been addressed in tabular form in Chapter 8 as follows:

Construction Activities

Impacts

- Site Clearing - Dusting, vehicular emissions, erosion\runoff, loss of vegetation
- Site Earth Work - Dusting, vehicular emissions, erosion\runoff, loss of vegetation
- Road Construction - Dusting, vehicular emissions, erosion\runoff, loss of vegetation
- Site Building Construction - Dusting, noise, erosion\runoff
- Equipment Maintenance - Air emissions
- Labor Housing Construction - Dusting, vehicular emissions, erosion\runoff, loss of vegetation
- Labor Transportation - Air emissions

The above impacts will be minimized or eliminated through engineering controls and good construction practices such as dust suppression, maintaining equipment, revegetation, maintaining plans to respond to emergencies, and water and waste management.

Plant Operations

Impacts

- Stack Emissions - No significant impacts
- Water Usage - Potential decrease in available quantity
- Process Water Discharge - No significant impacts
- Plant Sewage Discharge - No significant impacts
- Noise Level - Potential nuisance to Local Population and Workers
- Solid Waste Disposal - Potential Recycling of materials
- Hazardous Waste Disposal - No significant impacts
- Electromagnetic Frequency - No significant impacts

The above impacts are estimated to be negligible and therefore no mitigating measures would be required.

Thus, all impacts that have been anticipated have been correspondingly eliminated or reduced through a combination of administrative and engineering controls or good construction practice. Therefore, no permanent negative impacts are anticipated as a result of construction or operation of the Krasnodar GRES. In fact, there are several overall positive impacts associated with construction and operation of the proposed facility.

6.4.6 Monitoring Requirements

Routine environmental monitoring of Krasnodar GRES activities, will be conducted in two stages: monitoring during construction and monitoring during operations. In both stages, monitoring data will be archived on-site and will also be submitted to the appropriate officials of the Ministry of Environmental Protection and Natural Resources (MEPNR) and to the representative of the Public Environmental Control Commission (PECC). The PECC shall be formed by a special decree of the Mostovskoy Region. In addition, one time background monitoring will be conducted prior to construction activities.

Background Monitoring

Prior to commencement of construction activities, the following areas shall be evaluated in order to establish up-to-date baseline conditions:

- Water quality parameters shall be measured in the Laba River 0.5 km upstream from the discharge point of the Mostovskoy wastewater treatment plant;
- Drinking water parameters shall be measured from the potable water intake;
- Noise levels shall be measured at and beyond the Krasnodar GRES facility boundaries.

Monitoring During Construction

Noise and dust will be measured in and around the Krasnodar GRES site on a monthly basis. Exact monitoring locations shall be approved by the PECC representative. In addition, CO and hydrocarbon emissions will be measured only for on-site motor vehicles which lack an official exhaust inspection certificate.

Air Monitoring During Operations

A continuous emission monitoring system will measure basic parameters of plant operation (discharge velocity, temperature, etc.) as well as concentrations of NO_x, SO_2, CO, C_nH_m, O_3, and particulates in the flue gas in compliance with the Russian regulatory documents for environmental control. An automated on-site meteorological station will measure and record the following: Wind direction; Wind velocity; Temperature; and Humidity. Both the continuous emission monitoring system and the meteorological station will be connected to a central data receiving station at the facility which will archive average values of the data for 3 minute, 30 minute, and 24 hour intervals.

On-site ambient air quality measurements will be obtained by environmental control laboratory staff for particulates, NO_x, SO_2, and CO at intervals determined by PECC.

Off-site air monitoring stations are planned for the following sites:

- Mostovskoy settlement;
- Perepravnaya settlement;
- Psebai settlement;
- Caucasus biosphere reserve.

The off-site air monitoring stations will measure and record the concentrations of NO_x, SO_2, CO, C_nH_m, and Vanadium in compliance with the Russian regulatory documents for environmental control.

Water Monitoring During Operations

A mobile water quality monitoring station will measure the following parameters:

External Detectors
- Temperature and humidity;
- Wind velocity;
- Wind direction;
- Water level;

Water Quality Measurements
- Temperature;
- pH and conductivity;
- Dissolved oxygen;
- Total organic carbon;
- Toxicity determination.

The water quality monitoring station will be used for surface water and monitoring well locations as follows:

Surface Water Locations
- Laba River - 0.5 km downstream of the Krasnodar GRES;
- Laba River - 0.5 km downstream of the Mostovskoy wastewater treatment plant;

Monitoring Well Locations
- Potable water intake;
- Adjacent to the mineralized waste storage tanks;
- Outside the fenceline of Krasnodar GRES.

Exact monitoring well locations will be determined in conjunction with PECC. Water quality monitoring shall be conducted periodically at intervals established by the local environmental control bodies of the MEPNR and the sanitary-epidemiological inspectorate of the Russian Federation.

6.5 Consideration Of Alternatives

Chapter 7 of the EA identifies and evaluates reasonable alternatives to the Krasnodar GRES location, design, operation, and other parameters in order to meet the ultimate objective of providing additional electrical power in the Krasnodar Krai and alleviating the current power deficit. The purpose of the analysis is to determine any options that may be more sound or beneficial from an environmental, sociocultural, or economic perspective than the originally conceived, designed, and proposed power plant. The specific alternatives evaluated for the Krasnodar GRES and associated conclusions are summarized below:

- The No Action Alternative: Due to the current and projected power deficit in the North Caucasus, the No Action Alternative was not considered to be a viable option.

- Alternative Power Generation Technologies: Alternative technologies evaluated included hydro power, wind energy, solar thermal, photovoltaics, and biomass energy. Due to acreage requirements, climactic considerations, cost and reliability, lead time, and the size of the North Caucasus power deficit, none of the alternative technologies evaluated is considered to be a viable alternative to the proposed project.

- Alternative Plant, Water Pipeline and Transmission Line Locations: Eighteen sites were evaluated as possible locations for the proposed power station by the Project Ownership Group. Site criteria evaluated included: land ownership, availability, and access; topography; existing and potential environmental impacts; availability of water; equipment transportation; proximity of gas pipeline; interconnection with regional transmission systems; and local infrastructure. The Mostovskoy site was determined to be the most suitable for construction and operation of the Krasnodar GRES. In addition, the plant electric transmission lines and water pipelines shall be sited such that they will not impact flora, fauna, or ecologically sensitive areas.

- Alternative Plant, Water Pipeline and Transmission Line Designs: Transmission lines and pipelines shall be designed in conformance with International Standards acceptable to the Russian Federation and the World Bank and will not impact any ecologically sensitive areas. The proposed combined cycle natural gas plant is, by its very nature and design, one of the cleanest and most efficient fossil fuel plants available. Therefore, no alternative designs were considered to be a viable option.

- Alternative Fuel Utilization: Alternative fuels evaluated included oil, lignite and coal. Due to increased air emissions, storage considerations, and availability, no alternative fuel to natural gas was considered to be a viable option.

- Alternative Water Supplies and Intakes: The current plant design requires process water to be taken from the Laba River and a 33 kilometer potable water pipeline to be constructed. On-site wells are recommended for further analysis in order to reduce both environmental impacts on the Laba River.

- Alternative Sanitary and Plant Wastewater Disposal: The current proposed design of the plant wastewater system ensures that the chemical and thermal quality of all effluents will meet or exceed all appropriate Russian Federation and World Bank standards. Sanitary wastes from the proposed facility shall be directed to the existing treatment plant in Mostovskoy which will be upgraded in order to accept the anticipated increase in flow. Alternative disposal options and releases have been judged as unacceptable. Therefore, there are no viable alternatives to the current sanitary and wastewater systems.

- Alternative Solid Waste Disposal: The proposed waste disposal plan calls for environmentally safe disposal and recycling and reuse of a portion of wastes generated. No viable alternatives to the current solid waste disposal plan were identified.

- Alternative Pollution Control Systems and Equipment: The proposed pollution control systems will cause all liquid and gaseous plant effluents to meet or exceed all Russian Federation and World Bank requirements. Therefore, no viable alternatives to the current pollution control systems were identified.

Each of these alternatives, which is described and discussed in Chapter 7, is evaluated for its advantages and disadvantages according to its overall effectiveness, feasibility, implementability, cost, and regulatory and community acceptance as appropriate and consistent with this project's objectives and the environment and infrastructure in the Krasnodar Krai and Mostovskoy areas.

The only viable alternative requiring further investigation of those evaluated concerned an alternative water supply. It was recommended that the installation and use of on-site wells be investigated as an alternative to water from the Laba River.

6.6 Consultation With Affected People

Guidance documents of the World Bank and the Russian Federation stress the importance of public participation in development projects. In accordance with Russian practice, preliminary meetings to discuss the Krasnodar GRES have been held with various governmental and nongovernmental organizations (NGOs). These meetings included:

1. Ownership Group, Regional Environmental Committee, Consultants, 23 February, 1995.
2. Krasnodar Regional Environmental Committee (KREC) 18 April and 24 August 1995.
3. Kuban Folk Peoples Academy of Environment (NGO) 25 May 1995.
4. KREC Department of Regional Environmental Expertise, September 1995.
5. Mostovskaya District Administration, 2 July 1995.
6. Mostovskaya District Representatives, 12 July 1995.
7. Public Hearing of Governmental and Non-Governmental Organizations, 26 December 1995.

The public hearing held on 26 December 1995 was held in accordance with World Bank guidelines. This public hearing was attended by governmental and non-governmental organizations as well as members of the mass media. The public hearing concluded with the generation of a signed decree stating that the Krasnodar GRES project has been found to be acceptable from a technological and environmental standpoint.

In addition, several public meetings were held to support the previously prepared 1991 ROTEP Feasibility Study, including:

1. 4 February 1991 - Meeting with the public of the Mostovskoy Township.
2. 17 August 1992 - Meeting of citizens employed in Brigade #2 of the Frunze Collective Farm.
3. May 1993 - Meeting in Mostovskoy.
4. 18 August 1995 - Meeting of citizens of the Frunze Collective Farm in the Perepravnaya Settlement.

Documentation of public meetings\hearings is included in Chapter 11 of the EA.

6.7 Institutional Requirements

In conjunction with engineering and administrative controls, effective environmental management and planning during the construction and operation of the Krasnodar GRES is required to prevent any adverse impact on the surrounding environment.

During the course of the development phase, the Owners Group will evolve into the project company, Kuban GRES. This company will manage the implementation of the project from issuing the invitation to bids through plant operation.

The project development phase of the project includes the development work by the Owner and its consultants, e.g., land acquisition, feasibility studies, environmental impact statements and regulatory permits. Sources of debt and equity financing and project contracts are also developed. This work is in progress.

During the construction phase of the project Kuban GRES will appoint a Project Manager who will have the overall technical and project management responsibility for administering the turnkey EPC contract. All functions of the project namely, purchasing, contract administration, engineering, construction, project control, schedules, costs, and quality control and assurance will report to the project manager. The project manager will be the sole point of contact for project contractors and will be responsible for resolving all contractors' issues relating to schedule, cost, change orders and will be responsible for controlling the budget. All correspondence from and to contractors will be by the project manager only.

The project management team will be responsible for review of design, engineering, procurement specifications submitted by the contractor for Owner's review and oversee construction to ensure that engineering, construction, and procurement are in compliance with the contract documents, applicable codes and standards, local and federal government regulations and conditions of environmental permits. The project management team will interface with the utility, the gas company, the oil supply company, the water supply company, the local government and the environmental authorities.

During the operation phase of the project Kuban GRES will be structured to take over from the project development organization at the close of construction and to transition smoothly into an organization representative of power utility operations. Prior to plant startup, and before staffing is in place, programs must be established to provide the necessary training to all operating, maintenance, technical, and clerical employees Detailed training programs must be developed to insure all members of the various crafts are tested to be competent in their respective work areas. These should include:

- Operator Training
- Maintenance Training
  - Electrical
  - Mechanical
  - Welding
  - Instruments and Controls
- Chemistry
- Equipment Operators
- Industrial Safety
- Management Information Systems
- Inventory Control
- Environmental Control
- Fuel Handling

Training facilities should be installed at an early stage in construction to provide for adequate training time of personnel prior to startup.

6.8 Gas Pipeline

A Preliminary Environmental Assessment Report of the gas pipeline which is needed to supply natural gas to the proposed Krasnodar GRES has been generated by Acres International Limited for RAO Gazprom. The gas pipeline portion of the overall project is being treated as a separate project because the pipeline will be constructed and owned by a different corporate entity than the

Krasnodar GRES plant and transmission lines. The Assessment presents pipeline routing alternatives and associated mitigation recommendations to be incorporated into the environmental design specifications for the pipeline project once a route has been selected.
The Environmental Assessment Report makes a preliminary recommendation of pipeline routing Alternative #1. Gas pipeline route Alternative #1 would be located along the river terraces that flank the west side of the Laba River valley and along the Khodz River valley, through the Adygey Autonomous area and the Mostovskoy District for a total length of approximately 41 kilometers. The specific conclusions and recommendations of the gas pipeline Environmental Assessment report generated by Acres International Limited are:

1) Based on information provided by the Russian counterparts, it appears that routing Alternative #1 is the most appropriate option to consider from an environmental and technical perspective. It is the shortest of the four routes; involves only one major river crossing, over the smaller of the region's two major rivers; passes through more stable terrain which appears to be less prone to landslides and gully erosion than the ridge-top options; and involves less impact on valley bottom soils than the other valley bottom routing alternative.

2) A preliminary recommendation has been given to Alternative #1, rather than a firm recommendation, because not enough information on sociocultural impacts of this route was available during the preparation of the Preliminary Pipeline Environmental Assessment report. A final decision on whether to proceed with this option or not, will depend on how the public perceives the sociocultural risks of this routing alternative compared to the others. However, it should be possible to construct and operate this gas pipeline with minimal adverse impacts to the environment and local communities if the mitigation recommendations set out in the Preliminary Pipeline Environmental Assessment report are followed.

3) The mitigation measures that have been recommended are aimed at protecting valuable agriculture soils; minimizing surface soil erosion and resulting degradation of water quality for human consumption and fish habitat; protecting remnant wildlife habitat within the area; and minimizing disruption and disturbance to local community life.

4) Once a final decision has been made on whether to proceed with Routing Alternative #1, it will be necessary to take the Preliminary Pipeline Environmental Assessment a step further. Site specific information will be required to answer questions concerning the specific location of resources that could be at risk along the preferred gas pipeline route. The mitigation recommendations outlined in the Preliminary Pipeline Environmental Assessment report, would then be incorporated into the environmental design specifications for the project, to ameliorate the particular impacts that are likely to occur, and to refine the alignment.

APPENDIX A

FINANCIAL ANALYSIS

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APPENDIX A -- FINANCIAL MODEL

CONTENTS

APPENDIX A.1 – FINANCIAL MODEL OUTPUT, BASE CASE

Total Project

Sources of Cash:	Nominal US$ ('000)	% Total
Debt	$500,000	65%
Equity	264,011	35%
Total Capital Investment	$764,011	100%

Equity Returns

Russian Equity Investors	15%
Foreign Equity Investors	#VALUE!

Required Tariff ('95 US$)	w/o VAT	w/ VAT
Option 1: Average Tariff ($/kWh)	$0.0302	$0.0366
Two Part Tariff		
Option 2a: Capacity Charge ($/kW/yr)	$92.00	$111.78
Option 2b: Energy Charge ($/kWh)	$0.0138	$0.0168

Debt Financing

World Bank Loan	$500,000	100%
Export Credit Agency/Vendor Financing	0	0%
Other Commercial Bank Financing	0	0%
Total Debt Financing	$500,000	100%

Total Project

Uses of Cash:	Nominal US$ ('000)	% Total
Base Project Cost	$419,039	55%
Duties, Excise, VAT, Special Taxes	173,843	23%
Physical Contingencies	66,156	9%
Real Russian vs. US Escalation	51,829	7%
Inflation	46,221	6%
Interest Paid During Construction	0	0%
Capitalized Interest During Const.	77,171	10%
Principal Paid During Construction	0	0%
Working Capital (through 2000)	18,422	2%
Less: Internally-Generated Cash	(88,669)	-12%
Total Project Cost to be Financed Externally	$764,011	100%

CONTENTS **PAGE NUMBER**

Lender Terms

World Bank Loan:

- $500 million draw-down during construction.
- Can be used to finance equipment (which must be procured through international competitive bidding), contingencies, escalation costs, inflation costs, and interest during construction.
- Cannot be used to finance taxes, duties, or equipment which is not procured through international competitive bidding.
- 5 year grace period for repayment of principal and interest.
- 8% interest rate, compounded annually. Actual interest rate may be lower, but lender transaction fees are imbedded in assumed 8% interest rate.
- Interest payable semi-annually.
- 17 year term to maturity.
- Principal amortized, at option of borrower, on straight-line basis in equal semi-annual installments or in equal semi-annual installments of principal and interest.
- Commitment, mobilization and other fees estimated at 2% of principal amount of loan payable at time of closing.
- Other terms and conditions subject to negotiation and may include covenants specifying minimum debt/equity ratio, cash balances, interest coverage ratios, etc. during the loan repayment period.

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	FINANCIAL STATEMENTS ('000 nominal US dollars)	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
	Project Year	1	2	3	4	5	6	7	8	9	10	11	12	13
1	**INCOME STATEMENT**													
2														
3	**Revenue - Net of VAT**	0	0	2,752	59,179	178,563	212,548	217,437	221,785	226,443	231,198	236,053	241,010	246,072
4														
5	**Production Expenses - Net of VAT**													
6	Variable O&M	0	0	78	1,706	5,202	6,239	6,428	6,600	6,781	6,965	7,125	7,289	7,457
7	Fixed O&M	0	0	2,635	7,056	9,012	9,770	10,507	11,208	11,915	12,620	12,987	13,358	13,733
8	Generation Expenses	0	0	1,615	33,102	73,167	83,790	85,717	87,431	89,268	92,054	94,927	97,889	100,944
9	Development Expenses	13,500	0	0	0	0	0	0	0	0	0	0	0	0
10	Accounting, Legal and Other Expenses	0	0	529	542	554	567	581	592	605	617	630	643	657
11	**Total Production Expenses**	13,500	0	4,857	42,406	87,934	100,367	103,233	105,832	108,569	112,256	115,669	119,180	122,792
12														
13	**Gross Income**	(13,500)	0	(2,105)	16,773	90,629	112,181	114,204	115,954	117,874	118,942	120,384	121,831	123,280
14														
15	**Administration & Overheads**													
16	Property Taxes	564	2,987	6,632	9,587	10,596	10,165	9,758	9,376	9,021	8,694	8,371	8,047	7,724
17	Depreciation Expense	0	0	8,945	22,271	28,565	30,509	30,606	30,774	31,018	31,210	31,454	31,848	32,259
18	**Total Operating Costs**	564	2,987	15,577	31,858	39,161	40,674	40,364	40,150	40,039	39,905	39,824	39,895	39,983
19														
20	**Operating Income**	(14,064)	(2,987)	(17,682)	(15,085)	51,468	71,507	73,840	75,804	77,836	79,037	80,560	81,935	83,297
21														
22	**Other (Expenses) / Revenues**													
23	Interest (Expenses) Income	(202)	(3,204)	(11,958)	(25,701)	(36,106)	(40,000)	(36,923)	(33,846)	(30,769)	(27,692)	(24,615)	(21,538)	(18,462)
24	Other	0	0	0	0	0	0	0	0	0	0	0	0	0
25	**Total Other (Expenses)/Revenue**	(202)	(3,204)	(11,958)	(25,701)	(36,106)	(40,000)	(36,923)	(33,846)	(30,769)	(27,692)	(24,615)	(21,538)	(18,462)
26														
27	**Income Before Taxes**	(14,266)	(6,190)	(29,640)	(40,786)	15,362	31,507	36,917	41,958	47,066	51,345	55,945	60,397	64,836
28														
29	**Income Taxes**	0	0	0	0	5,377	11,027	12,921	14,685	16,473	17,971	19,581	21,139	22,692
30	**Net Income**	(14,266)	(6,190)	(29,640)	(40,786)	9,985	20,480	23,996	27,272	30,593	33,374	36,364	39,258	42,143
31														
32	Bad Debt Expense	0	0	275	2,959	3,571	4,251	4,349	4,436	4,529	4,624	4,721	4,820	4,921
33	**Net Income After Bad Debt Expense**	(14,266)	(6,190)	(29,916)	(43,745)	6,414	16,229	19,647	22,837	26,064	28,750	31,643	34,438	37,222
34	**Dividends Paid**	0	0	0	0	12,287	11,403	56,338	58,845	61,296	39,292	41,942	45,023	48,093

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FINANCIAL STATEMENTS ('000 nominal US dollars)	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27	2023 28
1 **INCOME STATEMENT**															
2															
3 **Revenue - Net of VAT**	251,239	252,667	254,045	255,369	256,636	257,844	258,990	260,070	261,081	262,020	262,884	263,668	264,369	264,983	265,506
4															
5 **Production Expenses - Net of VAT**															
6 Variable O&M	7,627	7,685	7,742	7,798	7,852	7,904	7,954	8,001	8,047	8,090	8,131	8,169	8,201	8,230	8,256
7 Fixed O&M	14,115	14,501	14,895	15,295	15,701	16,114	16,534	16,962	17,396	17,839	18,290	18,749	19,151	19,562	19,982
8 Generation Expenses	104,095	105,733	107,373	109,012	110,648	112,281	113,908	115,527	117,136	118,732	120,315	121,880	123,427	124,950	126,449
9 Development Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 Accounting, Legal and Other Expenses	671	685	699	714	729	744	760	776	792	809	826	843	861	879	897
11 **Total Production Expenses**	126,508	128,604	130,709	132,818	134,930	137,043	139,155	141,265	143,371	145,470	147,561	149,641	151,639	153,621	155,585
12															
13 **Gross Income**	124,732	124,063	123,336	122,550	121,706	120,801	119,835	118,805	117,710	116,550	115,322	114,028	112,729	111,362	109,922
14															
15 **Administration & Overheads**															
16 Property Taxes	7,401	7,078	6,756	6,434	6,113	5,792	5,471	5,151	4,831	4,511	4,192	3,874	3,556	3,239	3,054
17 Depreciation Expense	32,688	33,134	33,600	34,085	34,591	35,119	35,668	36,242	36,839	37,462	38,111	38,788	39,494	40,229	32,186
18 **Total Operating Costs**	40,089	40,213	40,356	40,520	40,704	40,910	41,139	41,392	41,670	41,973	42,304	42,662	43,050	43,468	35,240
19															
20 **Operating Income**	84,643	83,851	82,980	82,031	81,002	79,891	78,695	77,412	76,040	74,577	73,019	71,364	69,680	67,894	74,682
21															
22 **Other (Expenses) / Revenues**															
23 Interest (Expenses) Income	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
24 Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25 **Total Other (Expenses)/Revenue**	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
26															
27 **Income Before Taxes**	69,258	71,543	73,749	75,877	77,925	79,891	78,695	77,412	76,040	74,577	73,019	71,364	69,680	67,894	74,682
28															
29 **Income Taxes**	24,240	25,040	25,812	26,557	27,274	27,962	27,543	27,094	26,614	26,102	25,557	24,977	24,388	23,763	26,139
30 **Net Income**	45,018	46,503	47,937	49,320	50,651	51,929	51,152	50,318	49,426	48,475	47,462	46,387	45,292	44,131	48,543
31															
32 Bad Debt Expense	5,025	5,053	5,081	5,107	5,133	5,157	5,180	5,201	5,222	5,240	5,258	5,273	5,287	5,300	5,310
33 **Net Income After Bad Debt Expense**	39,993	41,450	42,856	44,213	45,519	46,772	45,972	45,117	44,205	43,234	42,204	41,113	40,004	38,831	43,233
34 **Dividends Paid**	51,149	52,632	53,861	55,028	56,130	114,859	93,058	91,957	90,785	89,539	88,218	86,820	85,403	83,905	79,156

FINANCIAL STATEMENTS ('000 nominal US dollars)	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39
1 **INCOME STATEMENT**											
2											
3 **Revenue - Net of VAT**	265,935	266,264	266,490	266,608	266,614	266,502	266,268	265,906	265,412	264,780	264,004
4											
5 **Production Expenses - Net of VAT**											
6 Variable O&M	8,279	8,299	8,316	8,320	8,320	8,317	8,309	8,298	8,283	8,263	8,239
7 Fixed O&M	20,411	20,849	21,297	21,744	22,201	22,667	23,143	23,629	24,125	24,632	25,149
8 Generation Expenses	127,920	129,359	130,763	132,130	133,454	134,732	135,959	137,133	138,247	139,296	140,277
9 Development Expenses	0	0	0	0	0	0	0	0	0	0	0
10 Accounting, Legal and Other Expenses	916	935	955	975	996	1,017	1,038	1,060	1,082	1,105	1,128
11 **Total Production Expenses**	**157,526**	**159,443**	**161,332**	**163,169**	**164,970**	**166,732**	**168,450**	**170,119**	**171,736**	**173,296**	**174,793**
12											
13 **Gross Income**	**108,408**	**106,821**	**105,158**	**103,439**	**101,643**	**99,770**	**97,818**	**95,787**	**93,676**	**91,484**	**89,211**
14											
15 **Administration & Overheads**											
16 Property Taxes	3,068	3,176	3,315	3,455	3,599	3,747	3,860	3,980	4,106	4,239	4,379
17 Depreciation Expense	19,794	14,333	13,258	14,066	14,842	15,582	16,280	16,971	17,692	18,442	19,225
18 **Total Operating Costs**	**22,861**	**17,509**	**16,572**	**17,522**	**18,441**	**19,329**	**20,140**	**20,951**	**21,797**	**22,681**	**23,604**
19											
20 **Operating Income**	**85,547**	**89,312**	**88,586**	**85,918**	**83,202**	**80,441**	**77,678**	**74,836**	**71,878**	**68,803**	**65,607**
21											
22 **Other (Expenses) / Revenues**											
23 Interest (Expenses) Income	0	0	0	0	0	0	0	0	0	0	0
24 Other	0	0	0	0	0	0	0	0	0	0	0
25 **Total Other (Expenses)/Revenue**	0	0	0	0	0	0	0	0	0	0	0
26											
27 **Income Before Taxes**	**85,547**	**89,312**	**88,586**	**85,918**	**83,202**	**80,441**	**77,678**	**74,836**	**71,878**	**68,803**	**65,607**
28											
29 **Income Taxes**	29,941	31,259	31,005	30,071	29,121	28,154	27,187	26,193	25,157	24,081	22,962
30 **Net Income**	**55,606**	**58,053**	**57,581**	**55,847**	**54,081**	**52,287**	**50,490**	**48,643**	**46,721**	**44,722**	**42,645**
31											
32 Bad Debt Expense	5,319	5,325	5,330	5,332	5,332	5,330	5,325	5,318	5,308	5,296	5,280
33 **Net Income After Bad Debt Expense**	**50,287**	**52,727**	**52,251**	**50,514**	**48,749**	**46,957**	**45,165**	**43,325**	**41,413**	**39,426**	**37,365**
34 **Dividends Paid**	72,660	68,432	65,619	63,379	61,022	58,543	58,659	55,968	53,168	50,259	47,238

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	FINANCIAL STATEMENTS	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
	('000 nominal US dollars) Project Year	1	2	3	4	5	6	7	8	9	10	11	12	13
1	**CASH FLOW**													
2														
3	**Net Income**	(14,266)	(6,190)	(29,916)	(43,745)	6,414	16,229	19,647	22,837	26,064	28,750	31,643	34,438	37,222
4	Plus: Depreciation	0	0	8,945	22,271	28,565	30,509	30,606	30,774	31,018	31,210	31,454	31,848	32,259
5	Plus: VAT Recovery	0	0	592	12,724	38,391	45,698	46,749	47,684	48,685	25,966	25,883	26,194	26,505
6														
7	**Cash Flow Before Changes in W.C.**	(14,266)	(6,190)	(20,379)	(8,750)	73,370	92,435	97,002	101,294	105,768	85,926	88,979	92,480	95,986
8														
9	**Changes in Working Capital**													
10	Cash and Temporary Cash Investments	0	0	(1,587)	(38)	(36)	(39,317)	1,498	1,503	1,500	1,499	1,499	1,498	1,497
11	Accounts Receivable	0	0	(7,868)	(2,997)	(7,578)	(3,510)	(505)	(449)	(481)	(491)	(501)	(512)	(523)
12	Inventories	0	0	(8,676)	(208)	(195)	(227)	(214)	(190)	(204)	(208)	(213)	(217)	(222)
13	Advances	0	0	(1,990)	(262)	(3,129)	(1,024)	(147)	(131)	(140)	(143)	(146)	(149)	(153)
14	*Other Current Assets*	0	0	(362)	(48)	(569)	(186)	(27)	(24)	(26)	(26)	(27)	(27)	(28)
15	Accounts Payables	0	0	5,429	715	8,532	2,793	402	357	383	391	399	407	416
16	*Other Current Liabilities*	0	0	905	119	1,422	466	67	60	64	65	67	68	69
17	**Total Change in Working Capital**	0	0	(14,150)	(2,719)	(1,552)	(41,006)	1,074	1,125	1,096	1,087	1,077	1,067	1,058
18														
19	**Net Cash Flow from Operations**	(14,266)	(6,190)	(34,529)	(11,469)	71,818	51,430	98,076	102,419	106,863	87,013	90,056	93,547	97,044
20														
21	**Investments**													
22	Capital Expenditures	37,587	161,517	243,289	219,058	95,637	1,565	3,276	5,113	7,106	9,260	9,653	10,062	10,489
23														
24	**Net Cash Flow after Investments**	(51,853)	(167,707)	(277,819)	(230,527)	(23,819)	49,865	94,800	97,307	99,757	77,753	80,404	83,485	86,554
25														
26	**Financing**													
27	Issuance of Debt	31,797	101,271	163,668	126,094	0	0	0	0	0	0	0	0	0
28	Capitalized Interest	202	3,204	11,958	25,701	36,106	0	0	0	0	0	0	0	0
29	Repayment of Debt	0	0	0	0	0	38,462	38,462	38,462	38,462	38,462	38,462	38,462	38,462
30														
31	**Net Cash Flow after Financing**	(19,854)	(63,233)	(102,193)	(78,732)	12,287	11,403	56,338	58,845	61,296	39,292	41,942	45,023	48,093
32														
33	**Equity**													
34	Issuance of Equity	19,854	63,233	102,193	78,732	0	0	0	0	0	0	0	0	0
35	*Contingency Fund*	0	0	0	0	(0)	0	0	0	0	0	0	0	0
36	Funds Available to Equity Shareholders	0	0	0	0	12,287	11,403	56,338	58,845	61,296	39,292	41,942	45,023	48,093
37														
38	**Net Cash Flow after Equity**	0	0	0	0	0	0	0	0	0	0	0	0	0
39														
40	Beginning balance	0	0	0	0	0	0	0	0	0	0	0	0	0
41	Change in cash	0	0	0	0	0	0	0	0	0	0	0	0	0
42	Ending balance	0	0	0	0	0	0	0	0	0	0	0	0	0
43														
44	**Debt Service Ratio**		nm	nm	nm	nm	0.56	1.13	1.15	1.18	1.20	1.25	1.31	1.38

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FINANCIAL STATEMENTS ('000 nominal US dollars)	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27	2023 28
1 **CASH FLOW**															
2															
3 **Net Income**	39,993	41,450	42,856	44,213	45,519	46,772	45,972	45,117	44,205	43,234	42,204	41,113	40,004	38,831	43,233
4 Plus: Depreciation	32,688	33,134	33,600	34,085	34,591	35,119	35,668	36,242	36,839	37,462	38,111	38,788	39,494	40,229	32,186
5 Plus: VAT Recovery	26,817	26,674	26,517	26,348	26,167	25,972	25,764	25,543	25,308	25,058	24,794	24,516	24,237	23,943	23,633
6															
7 **Cash Flow Before Changes in W.C.**	99,498	101,257	102,973	104,646	106,277	107,863	107,405	106,901	106,351	105,755	105,110	104,417	103,735	103,003	99,052
8															
9 **Changes in Working Capital**															
10 Cash and Temporary Cash Investments	1,496	1,527	1,527	1,528	1,528	20,759	(9)	(9)	(8)	(8)	(7)	(6)	(6)	(5)	(4)
11 Accounts Receivable	(534)	(148)	(142)	(137)	(131)	(125)	(118)	(112)	(104)	(97)	(89)	(81)	(72)	(63)	(54)
12 Inventories	(226)	(231)	(236)	(241)	(246)	(251)	(256)	(262)	(267)	(273)	(279)	(284)	(290)	(296)	(303)
13 Advances	(156)	(43)	(42)	(40)	(38)	(36)	(35)	(33)	(30)	(28)	(26)	(24)	(21)	(19)	(16)
14 Other Current Assets	(28)	(8)	(8)	(7)	(7)	(7)	(6)	(6)	(6)	(5)	(5)	(4)	(4)	(3)	(3)
15 Accounts Payables	425	117	113	109	104	99	94	89	83	77	71	64	58	50	43
16 Other Current Liabilities	71	20	19	18	17	17	16	15	14	13	12	11	10	8	7
17 **Total Change in Working Capital**	1,047	1,234	1,232	1,230	1,228	20,456	(315)	(317)	(319)	(321)	(323)	(325)	(326)	(328)	(330)
18															
19 **Net Cash Flow from Operations**	100,545	102,492	104,205	105,876	107,504	128,319	107,090	106,584	106,032	105,434	104,787	104,093	103,409	102,675	98,723
20															
21 **Investments**															
22 Capital Expenditures	10,934	11,398	11,882	12,387	12,912	13,460	14,032	14,627	15,248	15,895	16,570	17,273	18,006	18,770	19,567
23															
24 **Net Cash Flow after Investments**	89,611	91,093	92,323	93,489	94,592	114,859	93,058	91,957	90,785	89,539	88,218	86,820	85,403	83,905	79,156
25															
26 **Financing**															
27 Issuance of Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28 Capitalized Interest	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29 Repayment of Debt	38,462	38,462	38,462	38,462	38,462	0	0	0	0	0	0	0	0	0	0
30															
31 **Net Cash Flow after Financing**	51,149	52,632	53,861	55,028	56,130	114,859	93,058	91,957	90,785	89,539	88,218	86,820	85,403	83,905	79,156
32															
33 **Equity**															
34 Issuance of Equity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35 Contingency Fund	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36 Funds Available to Equity Shareholders	51,149	52,632	53,861	55,028	56,130	114,859	93,058	91,957	90,785	89,539	88,218	86,820	85,403	83,905	79,156
37															
38 **Net Cash Flow after Equity**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39															
40 Beginning balance	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
41 Change in cash	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42 Ending balance	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43															
44 **Debt Service Ratio**	1.45	1.51	1.57	1.64	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm

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FINANCIAL STATEMENTS ('000 nominal US dollars)	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39
1 **CASH FLOW**											
2											
3 **Net Income**	50,287	52,727	52,251	50,514	48,749	46,957	45,165	43,325	41,413	39,426	37,365
4 Plus: Depreciation	19,794	14,333	13,258	14,068	14,842	15,582	16,280	16,971	17,692	18,442	19,225
5 Plus: VAT Recovery	23,308	22,967	22,609	22,239	21,853	21,451	21,031	20,594	20,140	19,669	19,180
6											
7 **Cash Flow Before Changes in W.C.**	93,389	90,027	88,118	86,820	85,445	83,989	82,476	80,891	79,244	77,538	75,770
8											
9 **Changes in Working Capital**											
10 Cash and Temporary Cash Investments	(4)	(3)	(2)	(1)	(0)	1	2	3	4	5	6
11 Accounts Receivable	(44)	(34)	(23)	(12)	(1)	12	24	37	51	65	80
12 Inventories	(309)	(316)	(322)	(329)	(336)	(343)	2,346	2,344	2,342	2,340	2,338
13 Advances	(13)	(10)	(7)	(4)	(0)	3	7	11	15	19	23
14 Other Current Assets	(2)	(2)	(1)	(1)	(0)	1	1	2	3	3	4
15 Accounts Payables	35	27	19	10	0	(9)	(19)	(30)	(41)	(52)	(64)
16 Other Current Liabilities	6	5	3	2	0	(2)	(3)	(5)	(7)	(9)	(11)
17 **Total Change in Working Capital**	(331)	(332)	(334)	(335)	(336)	(337)	2,358	2,362	2,367	2,372	2,377
18											
19 **Net Cash Flow from Operations**	93,058	89,695	87,784	86,485	85,109	83,652	84,834	83,253	81,611	79,910	78,147
20											
21 **Investments**											
22 Capital Expenditures	20,397	21,263	22,165	23,106	24,088	25,109	26,174	27,285	28,443	29,650	30,909
23											
24 **Net Cash Flow after Investments**	72,660	68,432	65,619	63,379	61,022	58,543	58,659	55,968	53,168	50,259	47,238
25											
26 **Financing**											
27 Issuance of Debt	0	0	0	0	0	0	0	0	0	0	0
28 Capitalized Interest	0	0	0	0	0	0	0	0	0	0	0
29 Repayment of Debt	0	0	0	0	0	0	0	0	0	0	0
30											
31 **Net Cash Flow after Financing**	72,660	68,432	65,619	63,379	61,022	58,543	58,659	55,968	53,168	50,259	47,238
32											
33 **Equity**											
34 Issuance of Equity	0	0	0	0	0	0	0	0	0	0	0
35 Contingency Fund	0	0	0	0	0	0	0	0	0	0	0
36 Funds Available to Equity Shareholders	72,660	68,432	65,619	63,379	61,022	58,543	58,659	55,968	53,168	50,259	47,238
37											
38 **Net Cash Flow after Equity**	0	0	0	0	0	0	0	0	0	0	0
39											
40 Beginning balance	0	0	0	0	0	0	0	0	0	0	0
41 Change in cash	0	0	0	0	0	0	0	0	0	0	0
42 Ending balance	0	0	0	0	0	0	0	0	0	0	0
43											
44 **Debt Service Ratio**	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm

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FINANCIAL STATEMENTS ('000 nominal US dollars) Project Year	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11	2007 12	2008 13
1 **BALANCE SHEET**													
2													
3 **Fixed Assets**													
4 Gross Fixed Assets	37,587	199,104	442,393	661,451	757,088	758,653	761,929	767,041	774,147	783,407	793,059	803,122	813,611
5 Less: Accumulated Depreciation	0	0	8,945	31,216	59,781	90,290	120,896	151,670	182,688	213,898	245,352	277,200	309,459
6 **Net Fixed Assets**	**37,587**	**199,104**	**433,448**	**630,234**	**697,306**	**668,363**	**641,033**	**615,372**	**591,460**	**569,509**	**547,707**	**525,922**	**504,152**
7													
8 **Current Assets**													
9 Cash and Temporary Cash Investments	0	0	1,587	1,625	1,661	40,978	39,479	37,977	36,477	34,977	33,479	31,981	30,484
10 Contingency Fund	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Accounts Receivable, Net	0	0	7,868	10,865	18,443	21,954	22,459	22,908	23,389	23,880	24,381	24,893	25,416
12 Inventories	0	0	8,676	8,885	9,080	9,307	9,521	9,711	9,915	10,124	10,336	10,553	10,775
13 Advances	0	0	1,990	2,253	5,381	6,406	6,553	6,684	6,824	6,968	7,114	7,263	7,416
14 Other	0	0	362	410	978	1,165	1,191	1,215	1,241	1,267	1,293	1,321	1,348
15 **Total Current Assets**	**0**	**0**	**20,484**	**24,037**	**35,544**	**79,809**	**79,203**	**78,495**	**77,846**	**77,215**	**76,604**	**76,012**	**75,439**
16													
17 **Total Assets**	**37,587**	**199,104**	**453,932**	**654,272**	**732,851**	**748,171**	**720,236**	**693,867**	**669,305**	**646,724**	**624,311**	**601,933**	**579,591**
18													
19 **Capitalization and Liabilities**													
20													
21 **Capital, Reserves and Long-Term Debt**													
22 Charter Capital	19,854	19,854	19,854	19,854	19,854	19,854	19,854	19,854	19,854	19,854	19,854	19,854	19,854
23 Additional Paid-in Capital	0	63,233	165,425	244,157	244,157	244,157	244,157	244,157	244,157	244,157	244,157	244,157	244,157
24 Retained Earnings	(14,266)	(20,456)	(49,780)	(80,801)	(48,283)	2,240	12,298	23,973	37,427	52,851	68,434	84,042	99,676
11 Long-Term Debt	31,999	136,473	312,099	463,894	500,000	461,538	423,077	384,615	346,154	307,692	269,231	230,769	192,308
12 **Total Capitalization**	**37,587**	**199,104**	**447,598**	**647,104**	**715,728**	**727,790**	**699,386**	**672,600**	**647,592**	**624,554**	**601,676**	**578,822**	**555,995**
13													
14 **Current Liabilities**													
15 Accounts payable	0	0	5,429	6,144	14,676	17,470	17,872	18,229	18,612	19,003	19,402	19,809	20,225
16 Other Liabilities and Creditors	0	0	905	1,024	2,446	2,912	2,979	3,038	3,102	3,167	3,234	3,302	3,371
17 **Total Current Liabilities**	**0**	**0**	**6,333**	**7,168**	**17,123**	**20,381**	**20,850**	**21,267**	**21,714**	**22,170**	**22,635**	**23,111**	**23,596**
18													
19 **Total Capitalization and Liabilities**	**37,587**	**199,104**	**453,932**	**654,272**	**732,851**	**748,171**	**720,236**	**693,867**	**669,305**	**646,724**	**624,311**	**601,933**	**579,591**
20													
21 Balance Check	0	0	0	(0)	0	0	0	(0)	(0)	0	0	0	0
22													
23 **ROA Calculations**													
24 Current Assets plus Inflation-Adjusted Gross Assets (A1)	38,338	206,335	488,572	740,704	873,877	940,878	963,880	986,920	1,013,940	1,044,399	1,076,265	1,109,616	1,144,533
25 Current Assets plus Inflation-Adjusted Net Assets (A2)	38,338	206,335	479,107	706,882	807,681	838,397	823,507	807,294	793,035	780,323	766,996	752,864	737,900
26 Operating Profits (P1)	(14,064)	(2,987)	(17,682)	(15,085)	51,468	71,507	73,840	75,804	77,836	79,037	80,560	81,935	83,297
27 Net Profits (P2)	(14,266)	(6,190)	(29,640)	(40,786)	9,985	20,480	23,996	27,272	30,593	33,374	36,364	39,258	42,143
28 **Operating Return on Gross Assets (P1) / (A1)**		nm	nm	nm	6.4%	7.9%	7.8%	7.8%	7.8%	7.7%	7.6%	7.5%	7.4%
29 **Net Return on Gross Assets (P2) / (A1)**		nm	nm	nm	1.2%	2.3%	2.5%	2.8%	3.1%	3.2%	3.4%	3.6%	3.7%
30 **Operating Return on Net Assets (P1) / (A2)**		nm	nm	nm	6.8%	8.7%	8.9%	9.3%	9.7%	10.0%	10.4%	10.8%	11.2%
31 **Net Return on Net Assets (P2) / (A2)**		nm	nm	nm	1.3%	2.5%	2.9%	3.3%	3.8%	4.2%	4.7%	5.2%	5.7%

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FINANCIAL STATEMENTS ('000 nominal US dollars)	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27	2023 28
1 **BALANCE SHEET**															
2															
3 **Fixed Assets**															
4 Gross Fixed Assets	824,545	835,944	847,826	860,213	873,125	886,585	900,617	915,244	930,491	946,386	962,956	980,229	998,234	1,017,004	1,036,571
5 Less: Accumulated Depreciation	342,147	375,281	408,881	442,966	477,557	512,676	548,344	584,586	621,425	658,887	696,999	735,787	775,280	815,510	847,696
6 **Net Fixed Assets**	**482,398**	**460,663**	**438,945**	**417,246**	**395,567**	**373,909**	**352,272**	**330,657**	**309,066**	**287,499**	**265,957**	**244,442**	**222,954**	**201,495**	**188,876**
7															
8 **Current Assets**															
9 Cash and Temporary Cash Investments	28,988	27,461	25,934	24,407	22,879	2,119	2,129	2,138	2,146	2,154	2,161	2,167	2,173	2,178	2,182
10 Contingency Fund	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Accounts Receivable, Net	25,950	26,097	26,240	26,376	26,507	26,632	26,750	26,862	26,966	27,063	27,153	27,234	27,306	27,369	27,424
12 Inventories	11,001	11,232	11,468	11,709	11,955	12,206	12,462	12,724	12,991	13,264	13,542	13,827	14,117	14,414	14,716
13 Advances	7,572	7,615	7,656	7,696	7,734	7,771	7,805	7,838	7,868	7,897	7,923	7,946	7,967	7,986	8,002
14 Other	1,377	1,384	1,392	1,399	1,406	1,413	1,419	1,425	1,431	1,436	1,440	1,445	1,449	1,452	1,455
15 ***Total Current Assets***	**74,887**	**73,790**	**72,690**	**71,587**	**70,481**	**50,141**	**50,566**	**50,986**	**51,402**	**51,813**	**52,219**	**52,618**	**53,012**	**53,399**	**53,778**
16															
17 **Total Assets**	**557,286**	**534,453**	**511,635**	**488,834**	**466,049**	**424,050**	**402,838**	**381,644**	**360,468**	**339,312**	**318,176**	**297,060**	**275,966**	**254,894**	**242,654**
18															
19 **Capitalization and Liabilities**															
20															
21 **Capital, Reserves and Long-Term Debt**															
22 Charter Capital	19,854	19,854	19,854	19,854	19,854	19,854	19,854	19,854	19,854	19,854	19,854	19,854	19,854	19,854	19,854
23 Additional Paid-in Capital	244,157	244,157	244,157	244,157	244,157	244,157	244,157	244,157	244,157	244,157	244,157	244,157	244,157	244,157	244,157
24 Retained Earnings	115,337	130,829	146,341	161,874	177,429	135,314	113,992	92,694	71,422	50,176	28,957	7,766	(13,396)	(34,527)	(46,817)
11 Long-Term Debt	153,846	115,385	76,923	38,462	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
12 **Total Capitalization**	**533,194**	**510,224**	**487,275**	**464,346**	**441,440**	**399,325**	**378,003**	**356,705**	**335,433**	**314,187**	**292,968**	**271,777**	**250,616**	**229,484**	**217,195**
13															
14 **Current Liabilities**															
15 Accounts payable	20,650	20,767	20,880	20,989	21,093	21,193	21,287	21,376	21,459	21,536	21,607	21,671	21,729	21,779	21,822
16 Other Liabilities and Creditors	3,442	3,461	3,480	3,498	3,516	3,532	3,548	3,563	3,576	3,589	3,601	3,612	3,621	3,630	3,637
17 ***Total Current Liabilities***	**24,091**	**24,228**	**24,360**	**24,487**	**24,609**	**24,725**	**24,835**	**24,938**	**25,035**	**25,125**	**25,208**	**25,283**	**25,350**	**25,409**	**25,460**
18															
19 **Total Capitalization and Liabilities**	**557,286**	**534,453**	**511,635**	**488,834**	**466,049**	**424,050**	**402,838**	**381,644**	**360,468**	**339,312**	**318,176**	**297,060**	**275,966**	**254,894**	**242,654**
20															
21 Balance Check	0	0	(0)	0	(0)	(0)	(0)	(0)	0	0	(0)	0	(0)	(0)	(0)
22															
23 **ROA Calculations**															
24 Current Assets plus Inflation-Adjusted Gross As	1,181,101	1,218,848	1,258,412	1,299,896	1,343,409	1,369,836	1,419,299	1,471,160	1,525,556	1,582,635	1,642,553	1,705,475	1,771,577	1,841,047	1,914,083
25 Current Assets plus Inflation-Adjusted Net Asse	722,075	704,796	686,574	667,379	647,179	606,710	585,940	564,064	541,048	516,856	491,451	464,795	436,851	407,578	392,748
26 Operating Profits (P1)	84,643	83,851	82,980	82,031	81,002	79,891	78,695	77,412	76,040	74,577	73,019	71,364	69,680	67,894	74,682
27 Net Profits (P2)	45,018	46,503	47,937	49,320	50,651	51,929	51,152	50,318	49,426	48,475	47,462	46,387	45,292	44,131	48,543
28 **Operating Return on Gross Assets (P1) / (A1**	7.3%	7.0%	6.7%	6.4%	6.1%	5.9%	5.6%	5.4%	5.1%	4.8%	4.5%	4.3%	4.0%	3.8%	4.0%
29 **Net Return on Gross Assets (P2) / (A1)**	3.9%	3.9%	3.9%	3.9%	3.8%	3.8%	3.7%	3.5%	3.3%	3.1%	2.9%	2.8%	2.6%	2.4%	2.6%
30 **Operating Return on Net Assets (P1) / (A2)**	11.6%	11.8%	11.9%	12.1%	12.3%	12.7%	13.2%	13.5%	13.8%	14.1%	14.5%	14.9%	15.5%	16.1%	18.7%
31 **Net Return on Net Assets (P2) / (A2)**	6.2%	6.5%	6.9%	7.3%	7.7%	8.3%	8.6%	8.8%	8.9%	9.2%	9.4%	9.7%	10.0%	10.5%	12.1%

FINANCIAL STATEMENTS ('000 nominal US dollars)	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39
1 **BALANCE SHEET**											
2											
3 **Fixed Assets**											
4 Gross Fixed Assets	1,056,968	1,078,231	1,100,396	1,123,502	1,147,588	1,172,697	1,198,872	1,226,157	1,254,600	1,284,251	1,315,159
5 Less: Accumulated Depreciation	867,489	881,823	895,080	909,147	923,989	939,571	955,851	972,823	990,514	1,008,956	1,028,182
6 **Net Fixed Assets**	**189,479**	**196,408**	**205,316**	**214,355**	**223,599**	**233,126**	**243,020**	**253,334**	**264,086**	**275,294**	**286,978**
7											
8 **Current Assets**											
9 Cash and Temporary Cash Investments	2,186	2,188	2,190	2,191	2,191	2,190	2,189	2,186	2,181	2,176	2,170
10 Contingency Fund	0	0	0	0	0	0	0	0	0	0	0
11 Accounts Receivable, Net	27,468	27,502	27,525	27,537	27,538	27,526	27,502	27,465	27,414	27,349	27,268
12 Inventories	15,025	15,341	15,663	15,992	16,328	16,671	14,325	11,981	9,640	7,300	4,962
13 Advances	8,014	8,024	8,031	8,035	8,035	8,032	8,025	8,014	7,999	7,980	7,956
14 Other	1,457	1,459	1,460	1,461	1,461	1,460	1,459	1,457	1,454	1,451	1,447
15 **Total Current Assets**	**54,151**	**54,515**	**54,870**	**55,216**	**55,553**	**55,879**	**53,499**	**51,102**	**48,688**	**46,255**	**43,804**
16											
17 **Total Assets**	**243,629**	**250,923**	**260,186**	**269,571**	**279,152**	**289,005**	**296,519**	**304,437**	**312,774**	**321,549**	**330,781**
18											
19 **Capitalization and Liabilities**											
20											
21 **Capital, Reserves and Long-Term Debt**											
22 Charter Capital	19,854	19,854	19,854	19,854	19,854	19,854	19,854	19,854	19,854	19,854	19,854
23 Additional Paid-in Capital	244,157	244,157	244,157	244,157	244,157	244,157	244,157	244,157	244,157	244,157	244,157
24 Retained Earnings	(45,882)	(38,620)	(29,379)	(20,005)	(10,425)	(561)	6,976	14,928	23,312	32,148	41,455
11 Long-Term Debt	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
12 **Total Capitalization**	**218,129**	**225,391**	**234,632**	**244,006**	**253,586**	**263,450**	**270,987**	**278,939**	**287,323**	**296,159**	**305,466**
13											
14 **Current Liabilities**											
15 Accounts payable	21,858	21,885	21,903	21,913	21,913	21,904	21,885	21,855	21,815	21,763	21,699
16 Other Liabilities and Creditors	3,643	3,647	3,651	3,652	3,652	3,651	3,648	3,643	3,636	3,627	3,616
17 **Total Current Liabilities**	**25,501**	**25,532**	**25,554**	**25,565**	**25,566**	**25,555**	**25,533**	**25,498**	**25,450**	**25,390**	**25,315**
18											
19 **Total Capitalization and Liabilities**	**243,629**	**250,923**	**260,186**	**269,571**	**279,152**	**289,005**	**296,519**	**304,437**	**312,774**	**321,549**	**330,781**
20											
21 Balance Check	(0)	(0)	(0)	0	0	0	0	0	0	0	0
22											
23 **ROA Calculations**											
24 Current Assets plus Inflation-Adjusted Gross As	1,990,896	2,071,711	2,156,766	2,246,314	2,340,625	2,439,984	2,542,000	2,649,687	2,763,389	2,883,470	3,010,318
25 Current Assets plus Inflation-Adjusted Net Asse	401,344	421,963	447,049	473,260	500,783	529,827	557,937	587,992	620,117	654,445	691,120
26 Operating Profits (P1)	85,547	89,312	88,586	85,918	83,202	80,441	77,678	74,836	71,878	68,803	65,607
27 Net Profits (P2)	55,606	58,053	57,581	55,847	54,081	52,287	50,490	48,643	46,721	44,722	42,645
28 **Operating Return on Gross Assets (P1) / (A1**	4.4%	4.4%	4.2%	3.9%	3.6%	3.4%	3.1%	2.9%	2.7%	2.4%	2.2%
29 **Net Return on Gross Assets (P2) / (A1)**	2.8%	2.9%	2.7%	2.5%	2.4%	2.2%	2.0%	1.9%	1.7%	1.6%	1.4%
30 **Operating Return on Net Assets (P1) / (A2)**	21.5%	21.7%	20.4%	18.7%	17.1%	15.6%	14.3%	13.1%	11.9%	10.8%	9.8%
31 **Net Return on Net Assets (P2) / (A2)**	14.0%	14.1%	13.3%	12.1%	11.1%	10.1%	9.3%	8.5%	7.7%	7.0%	6.3%

FINANCIAL STATEMENTS ('000 nominal US dollars)	Project Year	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11	2007 12	2008 13
1 **EQUITY CASH FLOWS & FINANCIAL INTERNAL RATES OF RETURN**														
2														
3 **Equity Contributions**	Percent of Total													
4 Russian Ownership Group	100%	19,854	63,233	102,193	78,732	0								
5 Non-Russian Investor(s)	0%	0	0	0	0	0								
6 Total Equity Contributions		19,854	63,233	102,193	78,732	0								
7														
8 **Equity Returns**	Percent of Total													
9 Russian Ownership Group	100%	0	0	0	0	12,287	11,403	56,338	58,845	61,296	39,292	41,942	45,023	48,093
10 Non-Russian Investor(s)	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Total Equity Returns		0	0	0	0	12,287	11,403	56,338	58,845	61,296	39,292	41,942	45,023	48,093
12														
13 **Equity Cash Flows**														
14 Russian Ownership Group		(19,854)	(63,233)	(102,193)	(78,732)	12,287	11,403	56,338	58,845	61,296	39,292	41,942	45,023	48,093
15 Non-Russian Investor(s)		0	0	0	0	0	0	0	0	0	0	0	0	0
16 Total Equity Cash Flows		(19,854)	(63,233)	(102,193)	(78,732)	12,287	11,403	56,338	58,845	61,296	39,292	41,942	45,023	48,093
17														
18 **Equity IRR**		Total					Current →							
19 Russian Ownership Group FIRR		15.0%					#NUM!	#NUM!	#NUM!	-5.6%	-1.9%	1.1%	3.6%	5.5%
20 Non-Russian Investor(s) FIRR		#VALUE!					#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!
21 Total Equity FIRR		15.0%					#NUM!	#NUM!	#NUM!	-5.6%	-1.9%	1.1%	3.6%	5.5%
22														
23 **Project FIRR Calculations**														
24 Cash Flows After Operations, Investments		(51,853)	(167,707)	(277,819)	(230,527)	(23,819)	49,865	94,800	97,307	99,757	77,753	80,404	83,485	86,554
25 Plus: Interest Expense		202	3,204	11,958	25,701	36,106	40,000	36,923	33,846	30,769	27,692	24,615	21,538	18,462
26 Net Free Cash Flow (Project, Before Financing)		(51,650)	(164,503)	(265,860)	(204,826)	12,287	89,865	131,723	131,153	130,527	105,446	105,019	105,023	105,016
27 **Project FIRR, Nominal**		12.0%												
28 **Project FIRR, Real (less average inflation)**		9.9%												

FINANCIAL STATEMENTS ('000 nominal US dollars)	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27	2023 28
1 **EQUITY CASH FLOWS & FINANCIAL INTERI**															
2															
3 **Equity Contributions**															
4 Russian Ownership Group															
5 Non-Russian Investor(s)															
6 Total Equity Contributions															
7															
8 **Equity Returns**															
9 Russian Ownership Group	51,149	52,632	53,861	55,028	56,130	114,859	93,058	91,957	90,785	89,539	88,218	86,820	85,403	83,905	79,156
10 Non-Russian Investor(s)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 *Total Equity Returns*	51,149	52,632	53,861	55,028	56,130	114,859	93,058	91,957	90,785	89,539	88,218	86,820	85,403	83,905	79,156
12															
13 **Equity Cash Flows**															
14 Russian Ownership Group	51,149	52,632	53,861	55,028	56,130	114,859	93,058	91,957	90,785	89,539	88,218	86,820	85,403	83,905	79,156
15 *Non-Russian Investor(s)*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16 Total Equity Cash Flows	51,149	52,632	53,861	55,028	56,130	114,859	93,058	91,957	90,785	89,539	88,218	86,820	85,403	83,905	79,156
17															
18 **Equity IRR**															
19 *Russian Ownership Group FIRR*	*7.1%*	*8.4%*	*9.4%*	*10.2%*	*10.8%*	*11.9%*	*12.5%*	*13.0%*	*13.4%*	*13.7%*	*14.0%*	*14.2%*	*14.3%*	*14.5%*	*14.6%*
20 Non-Russian Investor(s) FIRR	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!
21 Total Equity FIRR	7.1%	8.4%	9.4%	10.2%	10.8%	11.9%	12.5%	13.0%	13.4%	13.7%	14.0%	14.2%	14.3%	14.5%	14.6%
22															
23 **Project FIRR Calculations**															
24 Cash Flows After Operations, Investments	89,611	91,093	92,323	93,489	94,592	114,859	93,058	91,957	90,785	89,539	88,218	86,820	85,403	83,905	79,156
25 Plus: Interest Expense	15,385	12,308	9,231	6,154	3,077	0	0	0	0	0	0	0	0	0	0
26 Net Free Cash Flow (Project, Before Financing)	104,996	103,401	101,553	99,643	97,669	114,859	93,058	91,957	90,785	89,539	88,218	86,820	85,403	83,905	79,156
27 **Project FIRR, Nominal**															
28 **Project FIRR, Real (less average inflation)**															

FINANCIAL STATEMENTS ('000 nominal US dollars)	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39	Liquidation Value (Working Capital)
1 **EQUITY CASH FLOWS & FINANCIAL INTERI**												
2												
3 **Equity Contributions**												
4 Russian Ownership Group												
5 Non-Russian Investor(s)												
6 Total Equity Contributions												
7												
8 **Equity Returns**												
9 Russian Ownership Group	72,660	68,432	65,619	63,379	61,022	58,543	58,659	55,968	53,168	50,259	47,238	18,488
10 Non-Russian Investor(s)	0	0	0	0	0	0	0	0	0	0	0	0
11 Total Equity Returns	72,660	68,432	65,619	63,379	61,022	58,543	58,659	55,968	53,168	50,259	47,238	18,488
12												
13 **Equity Cash Flows**												
14 Russian Ownership Group	72,660	68,432	65,619	63,379	61,022	58,543	58,659	55,968	53,168	50,259	47,238	18,488
15 Non-Russian Investor(s)	0	0	0	0	0	0	0	0	0	0	0	#VALUE!
16 Total Equity Cash Flows	72,660	68,432	65,619	63,379	61,022	58,543	58,659	55,968	53,168	50,259	47,238	18,488
17												
18 **Equity IRR**												
19 Russian Ownership Group FIRR	14.7%	14.7%	14.8%	14.8%	14.9%	14.9%	14.9%	15.0%	15.0%	15.0%	15.0%	
20 Non-Russian Investor(s) FIRR	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	#NUM!	
21 Total Equity FIRR	14.7%	14.7%	14.8%	14.8%	14.9%	14.9%	14.9%	15.0%	15.0%	15.0%	15.0%	
22												
23 **Project FIRR Calculations**												
24 Cash Flows After Operations, Investments	72,660	68,432	65,619	63,379	61,022	58,543	58,659	55,968	53,168	50,259	47,238	18,488
25 Plus: Interest Expense	0	0	0	0	0	0	0	0	0	0	0	
26 Net Free Cash Flow (Project, Before Financing)	72,660	68,432	65,619	63,379	61,022	58,543	58,659	55,968	53,168	50,259	47,238	
27 ***Project FIRR, Nominal***												
28 **Project FIRR, Real (less average inflation)**												

FINANCIAL STATEMENTS ('000 nominal US dollars)	Project Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
		1	2	3	4	5	6	7	8	9	10	11	12	13
SCENARIO: BASE CASE														
Equity Contributions														
	Percent of Total													
Russian Ownership Group	100%	19,854	63,233	102,193	78,732	0								
Foreign	0%	0	0	0	0	0								
Total Dividends to Investors	100%	19,854	63,233	102,193	78,732	0								
Dividends to Investors														
Russian Ownership Group						12,287	11,403	56,338	58,845	61,296	39,292	41,942	45,023	48,093
Foreign						0	0	0	0	0	0	0	0	0
Total Dividends to Investors						12,287	11,403	56,338	58,845	61,296	39,292	41,942	45,023	48,093
Debt Amortization Schedule														
Beginning Balance		0	31,999	136,473	312,099	463,894	500,000	461,538	423,077	384,615	346,154	307,692	269,231	230,769
Drawdown (inclusive of Capitalized Interest)		31,999	104,474	175,626	151,795	36,106	0	0	0	0	0	0	0	0
Principal Repayment		0	0	0	0	0	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)
Ending Balance		31,999	136,473	312,099	463,894	500,000	461,538	423,077	384,615	346,154	307,692	269,231	230,769	192,308
Interest Accrued		(202)	(3,204)	(11,958)	(25,701)	(36,106)	(40,000)	(36,923)	(33,846)	(30,769)	(27,692)	(24,615)	(21,538)	(18,462)
Interest Paid		0	0	0	0	0	40,000	36,923	33,846	30,769	27,692	24,615	21,538	18,462
Capitalized Interest During Construction (cumulative)		202	3,406	15,364	41,065	77,171								
Project Cash Flows (Straight Line Principal Amortization)														
Revenues (exclusive of VAT)		--	--	2,752	59,179	178,563	212,548	217,437	221,785	226,443	231,198	236,053	241,010	246,072
Total Cash Flows Before Financing		(51,853)	(167,707)	(277,819)	(230,527)	(23,819)	89,865	131,723	131,153	130,527	105,446	105,019	105,023	105,016
New Debt Financing		31,999	104,474	175,626	151,795	36,106	0	0	0	0	0	0	0	0
New Equity Financing		19,854	63,233	102,193	78,732	0	0	0	0	0	0	0	0	0
Interest Paid		0	0	0	0	0	(40,000)	(36,923)	(33,846)	(30,769)	(27,692)	(24,615)	(21,538)	(18,462)
Principal		0	0	0	0	0	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)
Dividends		0	0	0	0	(12,287)	(11,403)	(56,338)	(58,845)	(61,296)	(39,292)	(41,942)	(45,023)	(48,093)

Payback and Return

	Assumed Equity Return	Total Investment	Year to Payback	Cash Dividends (2000-2014)	Cash Dividends Through 2034
Russian Ownership Group	15.0%	$264,011	2006	$758,180	$2,201,970
Foreign	#VALUE!	$0	nm	$0	$0

FINANCIAL STATEMENTS ('000 nominal US dollars)	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27	2023 28
SCENARIO: BASE CASE															
Equity Contributions															
Russian Ownership Group															
Foreign															
Total Dividends to Investors															
Dividends to Investors															
Russian Ownership Group	51,149	52,632	53,861	55,028	56,130	114,859	93,058	91,957	90,785	89,539	88,218	86,820	85,403	83,905	79,156
Foreign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Dividends to Investors	51,149	52,632	53,861	55,028	56,130	114,859	93,058	91,957	90,785	89,539	88,218	86,820	85,403	83,905	79,156
Debt Amortization Schedule															
Beginning Balance	192,308	153,846	115,385	76,923	38,462	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Principal Repayment	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Ending Balance	153,846	115,385	76,923	38,462	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Interest Accrued	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Interest Paid	15,385	12,308	9,231	6,154	3,077	0	0	0	0	0	0	0	0	0	0
Capitalized Interest During Construction (cumul															
Project Cash Flows (Straight Line Principal,															
Revenues (exclusive of VAT)	251,239	252,667	254,045	255,369	256,636	257,844	258,990	260,070	261,081	262,020	262,884	263,668	264,369	264,983	265,506
Total Cash Flows Before Financing	104,996	103,401	101,553	99,643	97,669	114,859	93,058	91,957	90,785	89,539	88,218	86,820	85,403	83,905	79,156
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Paid	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Principal	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Dividends	(51,149)	(52,632)	(53,861)	(55,028)	(56,130)	(114,859)	(93,058)	(91,957)	(90,785)	(89,539)	(88,218)	(86,820)	(85,403)	(83,905)	(79,156)
Payback and Return															
Russian Ownership Group															
Foreign															

FINANCIAL STATEMENTS ('000 nominal US dollars)	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39
SCENARIO: BASE CASE											
Equity Contributions											
Russian Ownership Group											
Foreign											
Total Dividends to Investors											
Dividends to Investors											
Russian Ownership Group	72,660	68,432	65,619	63,379	61,022	58,543	58,659	55,968	53,168	50,259	47,238
Foreign	0	0	0	0	0	0	0	0	0	0	0
Total Dividends to Investors	72,660	68,432	65,619	63,379	61,022	58,543	58,659	55,968	53,168	50,259	47,238
Debt Amortization Schedule											
Beginning Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0
Principal Repayment	0	0	0	0	0	0	0	0	0	0	0
Ending Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Interest Accrued	0	0	0	0	0	0	0	0	0	0	0
Interest Paid	0	0	0	0	0	0	0	0	0	0	0
Capitalized Interest During Construction (cumul											
Project Cash Flows (Straight Line Principal,											
Revenues (exclusive of VAT)	265,935	266,264	266,490	266,608	266,614	266,502	266,268	265,906	265,412	264,780	264,004
Total Cash Flows Before Financing	72,660	68,432	65,619	63,379	61,022	58,543	58,659	55,968	53,168	50,259	47,238
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0
Interest Paid	0	0	0	0	0	0	0	0	0	0	0
Principal	0	0	0	0	0	0	0	0	0	0	0
Dividends	(72,660)	(68,432)	(65,619)	(63,379)	(61,022)	(58,543)	(58,659)	(55,968)	(53,168)	(50,259)	(47,238)
Payback and Return											
Russian Ownership Group											
Foreign											

ASSUMPTIONS (Input Constant Dollars) Project Year	1995 0	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11
MACROECONOMIC ASSUMPTIONS												
1 **GENERAL ESCALATION RATES**												
2 Gas		2.0%	1.6%	2.1%	2.4%	2.2%	2.5%	2.3%	2.0%	2.1%	2.1%	2.1%
3 O&M, Non-Fuel Semi-Variable Costs		2.0%	1.6%	2.1%	2.4%	2.2%	2.5%	2.3%	2.0%	2.1%	2.1%	2.1%
4 Tariff Inflation Rate		2.0%	1.6%	2.1%	2.4%	2.2%	2.5%	2.3%	2.0%	2.1%	2.1%	2.1%
5 **ESCALATION FACTORS**												
6 Gas	1.00	1.02	1.04	1.06	1.08	1.11	1.13	1.16	1.18	1.21	1.23	1.26
7 O&M, Non-Fuel Semi-Variable Costs	1.00	1.02	1.04	1.06	1.08	1.11	1.13	1.16	1.18	1.21	1.23	1.26
8 Tariff Inflation Rate	1.00	1.02	1.04	1.06	1.08	1.11	1.13	1.16	1.18	1.21	1.23	1.26
9 **RUSSIAN VS. U.S. COSTS**												
10 Material	70.0%	73.0%	76.0%	79.0%	82.0%	85.0%	85.5%	86.0%	86.5%	87.0%	87.5%	88.0%
11 Equipment	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%	63.0%	66.0%	69.0%	72.0%	75.0%	78.0%
12 Labor cost	10.0%	14.0%	18.0%	22.0%	26.0%	30.0%	36.0%	42.0%	48.0%	54.0%	60.0%	62.7%
13 Labor productivity factor	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%	62.0%	64.0%	66.0%	68.0%	70.0%	72.0%
14 Labor -- Total Cost	20.0%	26.9%	33.3%	39.3%	44.8%	50.0%	58.1%	65.6%	72.7%	79.4%	85.7%	87.0%
15 **RUSSIAN VS. U.S. ESCALATION FACTORS**												
16 Equipment	1.00	1.04	1.08	1.12	1.16	1.20	1.26	1.32	1.38	1.44	1.50	1.56
17 Material	1.00	1.04	1.09	1.13	1.17	1.21	1.22	1.23	1.24	1.24	1.25	1.26
18 Labor	1.00	1.35	1.67	1.96	2.24	2.50	2.90	3.28	3.64	3.97	4.29	4.35
19 Average of Labor and Material (O&M, OOPS escalation)	1.00	1.19	1.38	1.55	1.71	1.86	2.06	2.25	2.44	2.61	2.77	2.80
20												
21 **CAP.EX., TAX, REVENUE, WORK.CAP.**												
22 **Capital Expenditures (000 US$ 1995)**												
23 Generation Plant												
24 Non-Russian Equipment (non-escalated)		21,143	86,137	125,287	107,669	45,026						
25 Non-Russian Indirect (non-escalated)		4,740	19,309	28,086	24,136	10,093						
26 Western Subtotal (infl'n escalated)		26,401	109,276	162,281	142,808	61,034						
27 Russian Equipment (real escalated)		3,327	13,978	20,936	18,517	7,963						
28 Russian Materials (real escalated)		2,524	10,852	15,950	14,133	6,088						
29 Russia Labor (real escalated)		2,322	10,942	19,084	18,453	8,518						
30 Russian Indirect (real escalated)		2,794	12,815	20,591	19,272	8,680						
31 Russian Subtotal (real & infl'n escalated)		11,186	50,352	81,008	76,250	34,603						
32 Generation Plant (real & infl'n escalated)		37,587	159,628	243,289	219,058	95,637	0	0	0	0	0	0
33 Years to Depreciate		25	25	25	25	25	25	25	25	25	25	25
34 Second Stage Total (real & inflation adj)		0	0	0	0	0	0	0	0	0	0	0
35 Years to Depreciate		25	25	25	25	25	25	25	25	25	25	25
36 Office Equipment		0	1,500	0	0	0	0	0	0	0	0	0
37 Years to Depreciate		7	7	7	7	7	7	7	7	7	7	7
38 Transmission Line												
39 Non-Russian Equipment (non-escalated)		0	0	0	0	0						
40 Non-Russian Indirect (non-escalated)		0	0	0	0	0						
41 Western Subtotal (infl'n escalated)		0	0	0	0	0						
42 Russian Equipment (real escalated)		0	0	0	0	0						
43 Russian Materials (real escalated)		0	0	0	0	0						
44 Russia Labor (real escalated)		0	0	0	0	0						
45 Russian Indirect (real escalated)		0	0	0	0	0						
46 Russian Subtotal (real & infl'n escalated)		0	0	0	0	0						
39 Transmission Line (real & infl'n escalated)		0	0	0	0	0	0	0	0	0	0	0
40 Years to Depreciate		25	25	25	25	25	25	25	25	25	25	25

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ASSUMPTIONS (Input Constant Dollars)	2007 12	2008 13	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25
MACROECONOMIC ASSUMPTIONS														
1 **GENERAL ESCALATION RATES**														
2 Gas	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%
3 O&M, Non-Fuel Semi-Variable Costs	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%
4 Tariff Inflation Rate	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%
5 **ESCALATION FACTORS**														
6 Gas	1.29	1.31	1.34	1.37	1.40	1.43	1.46	1.49	1.52	1.55	1.58	1.62	1.65	1.69
7 O&M, Non-Fuel Semi-Variable Costs	1.29	1.31	1.34	1.37	1.40	1.43	1.46	1.49	1.52	1.55	1.58	1.62	1.65	1.69
8 Tariff Inflation Rate	1.29	1.31	1.34	1.37	1.40	1.43	1.46	1.49	1.52	1.55	1.58	1.62	1.65	1.69
9 **RUSSIAN VS. U.S. COSTS**														
10 Material	88.5%	89.0%	89.5%	90.0%	90.6%	91.3%	91.9%	92.5%	93.1%	93.8%	94.4%	95.0%	95.6%	96.3%
11 *Equipment*	81.0%	84.0%	87.0%	90.0%	90.6%	91.3%	91.9%	92.5%	93.1%	93.8%	94.4%	95.0%	95.6%	96.3%
12 Labor cost	65.3%	68.0%	70.7%	73.3%	76.0%	78.7%	81.3%	84.0%	86.7%	89.3%	92.0%	94.7%	97.3%	100.0%
13 Labor productivity factor	74.0%	76.0%	78.0%	80.0%	82.0%	84.0%	86.0%	88.0%	90.0%	92.0%	94.0%	96.0%	98.0%	100.0%
14 Labor -- Total Cost	88.3%	89.5%	90.6%	91.7%	92.7%	93.7%	94.6%	95.5%	96.3%	97.1%	97.9%	98.6%	99.3%	100.0%
15 **RUSSIAN VS. U.S. ESCALATION FACTORS**														
16 Equipment	1.62	1.68	1.74	1.80	1.81	1.83	1.84	1.85	1.86	1.88	1.89	1.90	1.91	1.93
17 Material	1.26	1.27	1.28	1.29	1.29	1.30	1.31	1.32	1.33	1.34	1.35	1.36	1.37	1.38
18 Labor	4.41	4.47	4.53	4.58	4.63	4.68	4.73	4.77	4.81	4.86	4.89	4.93	4.97	5.00
19 Average of Labor and Material (O&M, OOPS escalatic	2.84	2.87	2.90	2.93	2.96	2.99	3.02	3.05	3.07	3.10	3.12	3.14	3.17	3.19
20														
21 **CAP.EX., TAX, REVENUE, WORK.CAP.**														
22 **Capital Expenditures (000 US$ 1995)**														
23 Generation Plant														
24 Non-Russian Equipment (non-escalated)														
25 Non-Russian Indirect (non-escalated)														
26 *Western Subtotal (infl'n escalated)*														
27 Russian Equipment (real escalated)														
28 Russian Materials (real escalated)														
29 Russia Labor (real escalated)														
30 Russian Indirect (real escalated)														
31 Russian Subtotal (real & inflt'n escalated)														
32 Generation Plant (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33 Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25
34 Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35 Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25
36 Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37 Years to Depreciate	7	7	7	7	7	7	7	7	7	7	7	7	7	7
38 Transmission Line														
39 Non-Russian Equipment (non-escalated)														
40 Non-Russian Indirect (non-escalated)														
41 Western Subtotal (infl'n escalated)														
42 Russian Equipment (real escalated)														
43 Russian Materials (real escalated)														
44 Russia Labor (real escalated)														
45 Russian Indirect (real escalated)														
46 Russian Subtotal (real & inflt'n escalated)														
39 Transmission Line (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40 Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25

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ASSUMPTIONS (Input Constant Dollars)	2021 26	2022 27	2023 28	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39
MACROECONOMIC ASSUMPTIONS														
1 **GENERAL ESCALATION RATES**														
2 Gas	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%
3 O&M, Non-Fuel Semi-Variable Costs	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%
4 Tariff Inflation Rate	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%
5 **ESCALATION FACTORS**														
6 Gas	1.72	1.76	1.79	1.83	1.87	1.91	1.95	1.99	2.03	2.08	2.12	2.16	2.21	2.26
7 O&M, Non-Fuel Semi-Variable Costs	1.72	1.76	1.79	1.83	1.87	1.91	1.95	1.99	2.03	2.08	2.12	2.16	2.21	2.26
8 Tariff Inflation Rate	1.72	1.76	1.79	1.83	1.87	1.91	1.95	1.99	2.03	2.08	2.12	2.16	2.21	2.26
9 **RUSSIAN VS. U.S. COSTS**														
10 Material	96.9%	97.5%	98.1%	98.8%	99.4%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
11 Equipment	96.9%	97.5%	98.1%	98.8%	99.4%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
12 Labor cost	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
13 Labor productivity factor	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
14 Labor -- Total Cost	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
15 **RUSSIAN VS. U.S. ESCALATION FACTORS**														
16 Equipment	1.94	1.95	1.96	1.98	1.99	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
17 Material	1.38	1.39	1.40	1.41	1.42	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
18 Labor	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
19 Average of Labor and Material (O&M, OOPS escalatic	3.19	3.20	3.20	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21
20														
21 **CAP.EX., TAX, REVENUE, WORK.CAP.**														
22 **Capital Expenditures (000 US$ 1995)**														
23 Generation Plant														
24 Non-Russian Equipment (non-escalated)														
25 Non-Russian Indirect (non-escalated)														
26 Western Subtotal (infl'n escalated)														
27 Russian Equipment (real escalated)														
28 Russian Materials (real escalated)														
29 Russia Labor (real escalated)														
30 Russian Indirect (real escalated)														
31 Russian Subtotal (real & infl'n escalated)														
32 Generation Plant (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33 Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25
34 Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35 Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25
36 Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37 Years to Depreciate	7	7	7	7	7	7	7	7	7	7	7	7	7	7
38 Transmission Line														
39 Non-Russian Equipment (non-escalated)														
40 Non-Russian Indirect (non-escalated)														
41 Western Subtotal (infl'n escalated)														
42 Russian Equipment (real escalated)														
43 Russian Materials (real escalated)														
44 Russia Labor (real escalated)														
45 Russian Indirect (real escalated)														
46 Russian Subtotal (real & infl'n escalated)														
39 Transmission Line (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40 Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25

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ASSUMPTIONS (Input Constant Dollars)	Project Year	1995 0	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11
41 Gas Pipeline													
42 Non-Russian Equipment (non-escalated)			0	0	0	0	0						
43 Non-Russian Indirect (non-escalated)			0	0	0	0	0						
44 Western Subtotal (infl'n escalated)			0	0	0	0	0						
45 Russian Equipment (real escalated)			0	0	0	0	0						
46 Russian Materials (real escalated)			0	0	0	0	0						
47 Russia Labor (real escalated)			0	0	0	0	0						
48 Russian Indirect (real escalated)			0	0	0	0	0						
49 Russian Subtotal (real & infl'n escalated)			0	0	0	0	0						
50 Gas Pipeline (real & infl'n escalated)			0	0	0	0	0	0	0	0	0	0	0
51 Years to Depreciate			25	25	25	25	25	25	25	25	25	25	25
52 Capital Repairs			0	0	0	0	0	1,135	2,322	3,553	4,837	6,173	6,303
53 Years to Depreciate			25	25	25	25	25	25	25	25	25	25	25
54													
55 **Other Revenue/Expenses**													
56 Government Subsidies			0	0	0	0	0	0	0	0	0	0	0
57 Bad Debts as % of Gross Revenues			15%	10%	5%	2%	2%	2%	2%	2%	2%	2%	2%
58 Interest income			0	0	0	0	0	0	0	0	0	0	0
59													
60 **Working Capital**	Long-Term Goal												
61 Cash and cash equivalents (days sales)	3		0	0	211	10	3	70	66	62	59	55	52
62 Accounts Receivables (days sales)	45		0	0	1080	85	45	45	45	45	45	45	45
63 Uncollectible Threshold (days sales)	45		0	0	1080	85	45	45	45	45	45	45	45
64 Inventories (days sales)	18		0	0	1151	55	19	16	16	16	16	16	16
65 Advances (days sales)	11		0	0	264	14	11	11	11	11	11	11	11
66 Other Current Assets (days sales)	2		0	0	48	3	2	2	2	2	2	2	2
67 Accounts Payables (days sales)	30		0	0	720	38	30	30	30	30	30	30	30
68 Other Current *Liabilities* (days sales)	5		0	0	120	6	5	5	5	5	5	5	5
69													

DRAFT -- FOR DISCUSSION PURPOSES

ASSUMPTIONS (Input Constant Dollars)	2007 12	2008 13	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25
41 Gas Pipeline														
42 Non-Russian Equipment (non-escalated)														
43 Non-Russian Indirect (non-escalated)														
44 Western Subtotal (infl'n escalated)														
45 Russian Equipment (real escalated)														
46 Russian Materials (real escalated)														
47 Russia Labor (real escalated)														
48 Russian Indirect (real escalated)														
49 Russian Subtotal (real & infl'n escalated)														
50 Gas Pipeline (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
51 Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25
52 Capital Repairs	6,435	6,570	6,708	6,849	6,993	7,140	7,289	7,443	7,599	7,758	7,921	8,088	8,258	8,431
53 Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25
54														
55 **Other Revenue/Expenses**														
56 Government Subsidies	0	0	0	0	0	0	0	0	0	0	0	0	0	0
57 Bad Debts as % of Gross Revenues	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
58 *Interest Income*	0	0	0	0	0	0	0	0	0	0	0	0	0	0
59														
60 **Working Capital**														
61 Cash and cash equivalents (days sales)	48	45	42	40	37	35	33	3	3	3	3	3	3	3
62 Accounts Receivables (days sales)	45	45	45	45	45	45	45	45	45	45	45	45	45	45
63 Uncollectible Threshold (days sales)	45	45	45	45	45	45	45	45	45	45	45	45	45	45
64 Inventories (days sales)	16	16	16	16	16	17	17	17	18	18	18	18	19	19
65 Advances (days sales)	11	11	11	11	11	11	11	11	11	11	11	11	11	11
66 Other Current Assets (days sales)	2	2	2	2	2	2	2	2	2	2	2	2	2	2
67 *Accounts Payables (days sales)*	30	30	30	30	30	30	30	30	30	30	30	30	30	30
68 Other Current Liabilities (days sales)	5	5	5	5	5	5	5	5	5	5	5	5	5	5
69														

ASSUMPTIONS (Input Constant Dollars)	2021 26	2022 27	2023 28	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39
41 Gas Pipeline														
42 Non-Russian Equipment (non-escalated)														
43 Non-Russian Indirect (non-escalated)														
44 Western Subtotal (infl'n escalated)														
45 Russian Equipment (real escalated)														
46 Russian Materials (real escalated)														
47 Russia Labor (real escalated)														
48 Russian Indirect (real escalated)														
49 Russian Subtotal (real & inflt'n escalated)														
50 Gas Pipeline (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
51 Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25
52 Capital Repairs	8,608	8,789	8,973	9,162	9,354	9,551	9,751	9,956	10,165	10,379	10,596	10,819	11,046	11,278
53 Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25
54														
55 **Other Revenue/Expenses**														
56 Government Subsidies	0	0	0	0	0	0	0	0	0	0	0	0	0	0
57 Bad Debts as % of Gross Revenues	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
58 Interest Income	0	0	0	0	0	0	0	0	0	0	0	0	0	0
59														
60 **Working Capital**														
61 Cash and cash equivalents (days sales)	3	3	3	3	3	3	3	3	3	3	3	3	3	3
62 Accounts Receivables (days sales)	45	45	45	45	45	45	45	45	45	45	45	45	45	45
63 Uncollectible Threshold (days sales)	45	45	45	45	45	45	45	45	45	45	45	45	45	45
64 Inventories (days sales)	19	20	20	21	21	21	22	22	23	20	16	13	10	7
65 Advances (days sales)	11	11	11	11	11	11	11	11	11	11	11	11	11	11
66 Other Current Assets (days sales)	2	2	2	2	2	2	2	2	2	2	2	2	2	2
67 Accounts Payables (days sales)	30	30	30	30	30	30	30	30	30	30	30	30	30	30
68 Other Current Liabilities (days sales)	5	5	5	5	5	5	5	5	5	5	5	5	5	5
69														

ASSUMPTIONS (Input Constant Dollars)	Project Year	1995 0	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11
70 **Total Amount of World Bank Loan**		$500,000											
71													
72 **World Bank Drawdown #1 (12/1/96)**													
73 Loan Amount ($000)		31,797											
74 Capitalized Interest		11,500											
75 Issue Date		12/1/96											
76 First Interest Payment		12/1/01											
77 First Principal Payment		12/1/01											
78 Last Principal Payment		12/1/13											
79 Fixed Interest Rate (%/year)		8.00%											
80 **World Bank Drawdown #2 (12/1/97)**													
81 Loan Amount ($000)		101,271											
82 Capitalized Interest		26,412											
83 Issue Date		12/1/97											
84 First Interest Payment		12/1/01											
85 First Principal Payment		12/1/01											
86 Last Principal Payment		12/1/13											
87 Fixed Interest Rate (%/year)		8.00%											
88 **World Bank Drawdown #3 (12/1/98)**													
89 Loan Amount ($000)		163,668											
90 Capitalized Interest		28,365											
91 Issue Date		12/1/98											
92 First Interest Payment		12/1/01											
93 First Principal Payment		12/1/01											
94 Last Principal Payment		12/1/13											
95 Fixed Interest Rate (%/year)		8.00%											
96 **World Bank Drawdown #4 (12/1/99)**													
97 Loan Amount ($000)		126,094											
98 Capitalized Interest		10,894											
99 Issue Date		12/1/99											
100 First Interest Payment		12/1/01											
101 First Principal Payment		12/1/01											
102 Last Principal Payment		12/1/13											
103 Fixed Interest Rate (%/year)		8.00%											
104 **World Bank Drawdown #5 (12/1/2000)**													
105 Loan Amount ($000)		0											
106 Capitalized Interest		0											
107 Issue Date		12/1/00											
108 First Interest Payment		12/1/01											
109 First Principal Payment		12/1/01											
110 Last Principal Payment		12/1/13											
111 Fixed Interest Rate (%/year)		8.00%											
112													

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ASSUMPTIONS (Input Constant Dollars)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	12	13	14	15	16	17	18	19	20	21	22	23	24	25
70 **Total Amount of World Bank Loan**														
71														
72 **World Bank Drawdown #1 (12/1/96)**														
73 Loan Amount ($000)														
74 Capitalized Interest														
75 Issue Date														
76 First Interest Payment														
77 First Principal Payment														
78 Last Principal Payment														
79 Fixed Interest Rate (%/year)														
80 **World Bank Drawdown #2 (12/1/97)**														
81 Loan Amount ($000)														
82 Capitalized Interest														
83 Issue Date														
84 First Interest Payment														
85 First Principal Payment														
86 Last Principal Payment														
87 Fixed Interest Rate (%/year)														
88 **World Bank Drawdown #3 (12/1/98)**														
89 Loan Amount ($000)														
90 Capitalized Interest														
91 Issue Date														
92 First Interest Payment														
93 First Principal Payment														
94 Last Principal Payment														
95 Fixed Interest Rate (%/year)														
96 **World Bank Drawdown #4 (12/1/99)**														
97 Loan Amount ($000)														
98 Capitalized Interest														
99 Issue Date														
100 First Interest Payment														
101 First Principal Payment														
102 Last Principal Payment														
103 Fixed Interest Rate (%/year)														
104 **World Bank Drawdown #5 (12/1/2000)**														
105 Loan Amount ($000)														
106 Capitalized Interest														
107 Issue Date														
108 First Interest Payment														
109 First Principal Payment														
110 Last Principal Payment														
111 Fixed Interest Rate (%/year)														
112														

244

ASSUMPTIONS (Input Constant Dollars)	2021 26	2022 27	2023 28	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39
70 **Total Amount of World Bank Loan**														
71														
72 **World Bank Drawdown #1 (12/1/96)**														
73 Loan Amount ($000)														
74 Capitalized Interest														
75 Issue Date														
76 First Interest Payment														
77 First Principal Payment														
78 Last Principal Payment														
79 Fixed Interest Rate (%/year)														
80 **World Bank Drawdown #2 (12/1/97)**														
81 Loan Amount ($000)														
82 Capitalized Interest														
83 Issue Date														
84 First Interest Payment														
85 First Principal Payment														
86 Last Principal Payment														
87 Fixed Interest Rate (%/year)														
88 **World Bank Drawdown #3 (12/1/98)**														
89 Loan Amount ($000)														
90 Capitalized Interest														
91 Issue Date														
92 First Interest Payment														
93 First Principal Payment														
94 Last Principal Payment														
95 Fixed Interest Rate (%/year)														
96 **World Bank Drawdown #4 (12/1/99)**														
97 Loan Amount ($000)														
98 Capitalized Interest														
99 Issue Date														
100 First Interest Payment														
101 First Principal Payment														
102 Last Principal Payment														
103 Fixed Interest Rate (%/year)														
104 **World Bank Drawdown #5 (12/1/2000)**														
105 Loan Amount ($000)														
106 Capitalized Interest														
107 Issue Date														
108 First Interest Payment														
109 First Principal Payment														
110 Last Principal Payment														
111 Fixed Interest Rate (%/year)														
112														

ASSUMPTIONS (Input Constant Dollars)	Project Year	1995 0	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11
113 **Total Amount of Other ECA Loan**		0											
114													
115 **Other ECA Drawdown #1 (12/1/96)**													
116 Loan Amount ($000)		0											
117 Issue Date		12/1/96											
118 First Interest Payment		12/1/97											
119 First Principal Payment		12/1/99											
120 Last Principal Payment		12/1/04											
121 Fixed Interest Rate (%/year)		8.00%											
122													
123 **Other ECA Drawdown #2 (12/1/97)**													
124 Loan Amount ($000)		0											
125 Issue Date		12/1/97											
126 First Interest Payment		12/1/98											
127 First Principal Payment		12/1/99											
128 Last Principal Payment		12/1/04											
129 Fixed Interest Rate (%/year)		8.00%											
130 **Other ECA Drawdown #3 (12/1/98)**													
131 Loan Amount ($000)		0											
132 Issue Date		12/1/98											
133 First Interest Payment		12/1/99											
134 First Principal Payment		12/1/99											
135 Last Principal Payment		12/1/04											
136 Fixed Interest Rate (%/year)		8.00%											
137 **Other ECA Drawdown #4 (12/1/99)**													
138 Loan Amount ($000)		0											
139 Issue Date		12/1/99											
140 First Interest Payment		12/1/99											
141 First Principal Payment		12/1/99											
142 Last Principal Payment		12/1/04											
143 Fixed Interest Rate (%/year)		8.00%											
144													
145 **Assumed Capital Structure**	100.00%												
146 World Bank Debt as % of Total Capital	65.44%												
147 Other ILA Debt as % of Total Capital	0.00%												
148 Equity as % of Total Capital	34.56%												
149 Required Return on Equity	15.00%												
150													
151 **Total Amount of Equity Required**	**264,011**												
152													
153 New Equity		0	19,854	63,233	102,193	78,732	0	0	0	0	0	0	0
154													
155													
156 **TAX ASSUMPTIONS**													
157 Profit Tax (EBT)		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
158 Value added Tax (Gross revenue)		20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
159 Special Tax (Gross revenue)		1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
160 Property Tax (Net fixed asset + inventory)		1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
161 Duties/Excise Taxes (Imported materials/equipment)		20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
162													

ASSUMPTIONS (Input Constant Dollars)	2007 12	2008 13	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25
113 **Total Amount of Other ECA Loan**														
114														
115 **Other ECA Drawdown #1 (12/1/96)**														
116 Loan Amount ($000)														
117 Issue Date														
118 First Interest Payment														
119 First Principal Payment														
120 Last Principal Payment														
121 Fixed Interest Rate (%/year)														
122														
123 **Other ECA Drawdown #2 (12/1/97)**														
124 Loan Amount ($000)														
125 Issue Date														
126 First Interest Payment														
127 First Principal Payment														
128 Last Principal Payment														
129 Fixed Interest Rate (%/year)														
130 **Other ECA Drawdown #3 (12/1/98)**														
131 Loan Amount ($000)														
132 Issue Date														
133 First Interest Payment														
134 First Principal Payment														
135 Last Principal Payment														
136 Fixed Interest Rate (%/year)														
137 **Other ECA Drawdown #4 (12/1/99)**														
138 Loan Amount ($000)														
139 Issue Date														
140 First Interest Payment														
141 First Principal Payment														
142 Last Principal Payment														
143 Fixed Interest Rate (%/year)														
144														
145 **Assumed Capital Structure**														
146 World Bank Debt as % of Total Capital														
147 Other ILA Debt as % of Total Capital														
148 Equity as % of Total Capital														
149 Required Return on Equity														
150														
151 **Total Amount of Equity Required**														
152														
153 New Equity	0	0	0	0	0	0	0	0	0	0	0	0	0	0
154														
155														
156 **TAX ASSUMPTIONS**														
157 Profit Tax (EBT)	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
158 Value added Tax (Gross revenue)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
159 Special Tax (Gross revenue)	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
160 Property Tax (Net fixed asset + inventory)	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
161 Duties/Excise Taxes (Imported materials/equipment)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
162														

ASSUMPTIONS (Input Constant Dollars)	2021 26	2022 27	2023 28	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39
113 **Total Amount of Other ECA Loan**														
114														
115 **Other ECA Drawdown #1 (12/1/96)**														
116 Loan Amount ($000)														
117 Issue Date														
118 First Interest Payment														
119 First Principal Payment														
120 Last Principal Payment														
121 Fixed Interest Rate (%/year)														
122														
123 **Other ECA Drawdown #2 (12/1/97)**														
124 Loan Amount ($000)														
125 Issue Date														
126 First Interest Payment														
127 First Principal Payment														
128 Last Principal Payment														
129 Fixed Interest Rate (%/year)														
130 **Other ECA Drawdown #3 (12/1/98)**														
131 Loan Amount ($000)														
132 Issue Date														
133 First Interest Payment														
134 First Principal Payment														
135 Last Principal Payment														
136 Fixed Interest Rate (%/year)														
137 **Other ECA Drawdown #4 (12/1/99)**														
138 Loan Amount ($000)														
139 Issue Date														
140 First Interest Payment														
141 First Principal Payment														
142 Last Principal Payment														
143 Fixed Interest Rate (%/year)														
144														
145 **Assumed Capital Structure**														
146 World Bank Debt as % of Total Capital														
147 Other ILA Debt as % of Total Capital														
148 Equity as % of Total Capital														
149 Required Return on Equity														
150														
151 **Total Amount of Equity Required**														
152														
153 New Equity	0	0	0	0	0	0	0	0	0	0	0	0	0	0
154														
155														
156 **TAX ASSUMPTIONS**														
157 Profit Tax (EBT)	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
158 Value added Tax (Gross revenue)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
159 Special Tax (Gross revenue)	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
160 Property Tax (Net fixed asset + Inventory)	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
161 Duties/Excise Taxes (Imported materials/equipment)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
162														

ASSUMPTIONS (Input Constant Dollars)	Project Year	1995 0	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11
163 **SYSTEM GENERATION**													
164 Nominal Capacity (MW) - GT mode, 1st Module			0	0	300	300	0	0	0	0	0	0	0
165 Net Rated Capacity - GT mode. 1st Module			0	0	295	295	0	0	0	0	0	0	0
166 Nominal Capacity (MW) - GT mode, 2nd Module			0	0	0	300	300	0	0	0	0	0	0
167 Net Rated Capacity - GT mode. 2nd Module			0	0	0	295	295	0	0	0	0	0	0
168 Nominal Capacity (MW) - CC mode, 1st Module			0	0	0	450	450	450	450	450	450	450	450
169 Net Rated Capacity - CC mode, 1st Module			0	0	0	443	443	443	443	443	443	443	443
170 Nominal Capacity (MW) - CC mode, 2nd Module			0	0	0	0	450	450	450	450	450	450	450
171 Net Rated Capacity - CC mode, 2nd Module			0	0	0	0	443	443	443	443	443	443	443
172 Total Nominal Capacity			0	0	300	750	900	900	900	900	900	900	900
173 Total Net Rated Capacity			0	0	295	738	886	886	886	886	886	886	886
174 Months of Operation - GT mode, 1st Module			0	0	1	11	0	0	0	0	0	0	0
175 Months of Operation - GT mode, 2nd Module			0	0	0	7	5	0	0	0	0	0	0
176 Months of Operation - CC mode, 1st Module			0	0	0	1	12	12	12	12	12	12	12
177 Months of Operation - CC mode, 2nd Module			0	0	0	0	7	12	12	12	12	12	12
178 Load Factor - GT mode			40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
179 Load Factor - CC mode			80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
180 Operating Hours - GT mode, 1st Module				0	292	3,212	0	0	0	0	0	0	0
181 Operating Hours - GT mode, 2nd Module				0	0	2,044	1,460	0	0	0	0	0	0
182 Operating Hours - CC mode, 1st Module				0	0	584	7,008	7,008	7,008	7,008	7,008	7,008	7,008
183 Operating Hours - CC mode, 2nd Module				0	0	0	4,088	7,008	7,008	7,008	7,008	7,008	7,008
184 Production (GWh) - GT mode			0	0	88	1,577	438	0	0	0	0	0	0
185 Production (GWh) - CC mode			0	0	0	263	4,993	6,307	6,307	6,307	6,307	6,307	6,307
186 Total Production (GWh)			0	0	88	1,840	5,431	6,307	6,307	6,307	6,307	6,307	6,307
187 Supplied (GWh) - GT mode			0	0	86	1,552	431	0	0	0	0	0	0
188 Supplied (GWh) - CC mode			0	0	0	259	4,916	6,209	6,209	6,209	6,209	6,209	6,209
189 Total Supplied (GWh) at the busbar			0	0	86	1,811	5,347	6,209	6,209	6,209	6,209	6,209	6,209
190													
191 **FUEL CONSUMPTION CALCULATIONS**	**Heat Rate**												
192 BTU/kWh - GT mode	10,080		0.00	0.00	0.88	15.89	4.42	0.00	0.00	0.00	0.00	0.00	0.00
193 BTU/kWh - CC mode	6,771		0.00	0.00	0.00	1.78	33.81	42.71	42.71	42.71	42.71	42.71	42.71
194 Gas - million MCM			0.000	0.000	0.025	0.501	1.083	1.210	1.210	1.210	1.210	1.210	1.210
195 Cost (per MCM) real escalation begins 2005		$61.00	$61.00	$61.00	$61.00	$61.00	$61.00	$61.00	$61.00	$61.00	$61.00	$61.61	$62.23
196 Cost (per MCM) inflation adjusted		$61.00	$62.22	$63.22	$64.54	$66.09	$67.55	$69.23	$70.83	$72.24	$73.76	$76.06	$78.44
197 Variable Fuel Cost ($/kWh)					$0.0184	$0.0180	$0.0135	$0.0133	$0.0136	$0.0139	$0.0142	$0.0146	$0.0151
198													

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ASSUMPTIONS (Input Constant Dollars)	2007 12	2008 13	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25
163 **SYSTEM GENERATION**														
164 Nominal Capacity (MW) - GT mode, 1st Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0
165 Net Rated Capacity - GT mode. 1st Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0
166 Nominal Capacity (MW) - GT mode, 2nd Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0
167 Net Rated Capacity - GT mode. 2nd Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0
168 Nominal Capacity (MW) - CC mode, 1st Module	450	450	450	450	450	450	450	450	450	450	450	450	450	450
169 Net Rated Capacity - CC mode, 1st Module	443	443	443	443	443	443	443	443	443	443	443	443	443	443
170 Nominal Capacity (MW) - CC mode, 2nd Module	450	450	450	450	450	450	450	450	450	450	450	450	450	450
171 Net Rated Capacity - CC mode, 2nd Module	443	443	443	443	443	443	443	443	443	443	443	443	443	443
172 Total Nominal Capacity	900	900	900	900	900	900	900	900	900	900	900	900	900	900
173 Total Net Rated Capacity	886	886	886	886	886	886	886	886	886	886	886	886	886	886
174 Months of Operation - GT mode, 1st Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0
175 Months of Operation - GT mode, 2nd Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0
176 Months of Operation - CC mode, 1st Module	12	12	12	12	12	12	12	12	12	12	12	12	12	12
177 Months of Operation - CC mode, 2nd Module	12	12	12	12	12	12	12	12	12	12	12	12	12	12
178 Load Factor - GT mode	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
179 Load Factor - CC mode	80.0%	80.0%	80.0%	78.8%	77.6%	76.4%	75.2%	74.0%	72.8%	71.6%	70.4%	69.2%	68.0%	66.8%
180 Operating Hours - GT mode, 1st Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0
181 Operating Hours - GT mode, 2nd Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0
182 Operating Hours - CC mode, 1st Module	7,008	7,008	7,008	6,903	6,798	6,693	6,588	6,482	6,377	6,272	6,167	6,062	5,957	5,852
183 Operating Hours - CC mode, 2nd Module	7,008	7,008	7,008	6,903	6,798	6,693	6,588	6,482	6,377	6,272	6,167	6,062	5,957	5,852
184 Production (GWh) - GT mode	0	0	0	0	0	0	0	0	0	0	0	0	0	0
185 Production (GWh) - CC mode	6,307	6,307	6,307	6,213	6,118	6,023	5,929	5,834	5,740	5,645	5,550	5,456	5,361	5,267
186 Total Production (GWh)	6,307	6,307	6,307	6,213	6,118	6,023	5,929	5,834	5,740	5,645	5,550	5,456	5,361	5,267
187 Supplied (GWh) - GT mode	0	0	0	0	0	0	0	0	0	0	0	0	0	0
188 Supplied (GWh) - CC mode	6,209	6,209	6,209	6,116	6,023	5,930	5,837	5,743	5,650	5,557	5,464	5,371	5,278	5,185
189 Total Supplied (GWh) at the busbar	6,209	6,209	6,209	6,116	6,023	5,930	5,837	5,743	5,650	5,557	5,464	5,371	5,278	5,185
190								0.005						
191 **FUEL CONSUMPTION CALCULATIONS**														
192 BTU/kWh - GT mode	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
193 BTU/kWh - CC mode	42.71	42.71	42.71	42.07	41.42	40.78	40.14	39.50	38.86	38.22	37.58	36.94	36.30	35.66
194 Gas - million MCM	1.210	1.210	1.210	1.192	1.174	1.156	1.138	1.119	1.101	1.083	1.065	1.047	1.029	1.011
195 Cost (per MCM) real escalation begins 2005	$62.85	$63.48	$64.11	$64.75	$65.40	$66.05	$66.71	$67.38	$68.06	$68.74	$69.42	$70.12	$70.82	$71.53
196 Cost (per MCM) inflation adjusted	$80.88	$83.41	$86.01	$88.70	$91.47	$94.32	$97.26	$100.30	$103.43	$106.66	$109.99	$113.42	$116.96	$120.61
197 Variable Fuel Cost ($/kWh)	$0.0155	$0.0160	$0.0165	$0.0170	$0.0176	$0.0181	$0.0187	$0.0192	$0.0198	$0.0205	$0.0211	$0.0218	$0.0224	$0.0231
198														

ASSUMPTIONS (Input Constant Dollars)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	26	27	28	29	30	31	32	33	34	35	36	37	38	39
163 **SYSTEM GENERATION**														
164 Nominal Capacity (MW) - GT mode, 1st Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0
165 Net Rated Capacity - GT mode. 1st Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0
166 Nominal Capacity (MW) - GT mode, 2nd Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0
167 Net Rated Capacity - GT mode. 2nd Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0
168 Nominal Capacity (MW) - CC mode, 1st Module	450	450	450	450	450	450	450	450	450	450	450	450	450	450
169 Net Rated Capacity - CC mode, 1st Module	443	443	443	443	443	443	443	443	443	443	443	443	443	443
170 Nominal Capacity (MW) - CC mode, 2nd Module	450	450	450	450	450	450	450	450	450	450	450	450	450	450
171 Net Rated Capacity - CC mode, 2nd Module	443	443	443	443	443	443	443	443	443	443	443	443	443	443
172 Total Nominal Capacity	900	900	900	900	900	900	900	900	900	900	900	900	900	900
173 Total Net Rated Capacity	886	886	886	886	886	886	886	886	886	886	886	886	886	886
174 Months of Operation - GT mode, 1st Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0
175 Months of Operation - GT mode, 2nd Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0
176 Months of Operation - CC mode, 1st Module	12	12	12	12	12	12	12	12	12	12	12	12	12	12
177 Months of Operation - CC mode, 2nd Module	12	12	12	12	12	12	12	12	12	12	12	12	12	12
178 Load Factor - GT mode	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
179 Load Factor - CC mode	65.6%	64.4%	63.2%	62.0%	60.8%	59.6%	58.4%	57.2%	56.0%	54.8%	53.6%	52.4%	51.2%	50.0%
180 Operating Hours - GT mode, 1st Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0
181 Operating Hours - GT mode, 2nd Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0
182 Operating Hours - CC mode, 1st Module	5,747	5,641	5,536	5,431	5,326	5,221	5,116	5,011	4,906	4,800	4,695	4,590	4,485	4,380
183 Operating Hours - CC mode, 2nd Module	5,747	5,641	5,536	5,431	5,326	5,221	5,116	5,011	4,906	4,800	4,695	4,590	4,485	4,380
184 Production (GWh) - GT mode	0	0	0	0	0	0	0	0	0	0	0	0	0	0
185 Production (GWh) - CC mode	5,172	5,077	4,983	4,888	4,793	4,699	4,604	4,510	4,415	4,320	4,226	4,131	4,037	3,942
186 Total Production (GWh)	5,172	5,077	4,983	4,888	4,793	4,699	4,604	4,510	4,415	4,320	4,226	4,131	4,037	3,942
187 Supplied (GWh) - GT mode	0	0	0	0	0	0	0	0	0	0	0	0	0	0
188 Supplied (GWh) - CC mode	5,091	4,998	4,905	4,812	4,719	4,626	4,533	4,439	4,346	4,253	4,160	4,067	3,974	3,881
189 Total Supplied (GWh) at the busbar	5,091	4,998	4,905	4,812	4,719	4,626	4,533	4,439	4,346	4,253	4,160	4,067	3,974	3,881
190														
191 **FUEL CONSUMPTION CALCULATIONS**														
192 BTU/kWh - GT mode	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
193 BTU/kWh - CC mode	35.02	34.38	33.74	33.10	32.46	31.82	31.18	30.53	29.89	29.25	28.61	27.97	27.33	26.69
194 *Gas - million* MCM	0.992	0.974	0.956	0.938	0.920	0.902	0.883	0.865	0.847	0.829	0.811	0.793	0.775	0.756
195 Cost (per MCM) real escalation begins 2005	$72.24	$72.96	$73.69	$74.43	$75.18	$75.93	$76.69	$77.45	$78.23	$79.01	$79.80	$80.60	$81.40	$82.22
196 Cost (per MCM) Inflation adjusted	$124.37	$128.25	$132.26	$136.39	$140.64	$145.03	$149.56	$154.23	$159.04	$164.00	$169.12	$174.40	$179.84	$185.46
197 Variable Fuel Cost ($/kWh)	$0.0239	$0.0246	$0.0254	$0.0262	$0.0270	$0.0278	$0.0287	$0.0296	$0.0305	$0.0315	$0.0325	$0.0335	$0.0345	$0.0356
198														

ASSUMPTIONS (Input Constant Dollars)			1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Project Year			0	1	2	3	4	5	6	7	8	9	10	11
199 **O&M CALCULATIONS**	Total 1995	$/kW												
200 Fixed O&M Calculations	'000 $	(886 kW)												
201 Non-Russian Materials ($/kW/yr) (duties)	$3,550	$4.0068	$4.8081	$4.9043	$4.9828	$5.0874	$5.2095	$5.3241	$5.4572	$5.5827	$5.6944	$5.8140	$5.9360	$6.0607
202 Non-Russian OOPs ($/kW/yr)	$225	$0.2540	$0.2540	$0.2590	$0.2632	$0.2687	$0.2751	$0.2812	$0.2882	$0.2949	$0.3008	$0.3071	$0.3135	$0.3201
203 Russian Materials ($/kW/yr) (escalated)	$360	$0.4063	$0.4063	$0.4322	$0.4572	$0.4852	$0.5157	$0.5463	$0.5633	$0.5796	$0.5946	$0.6106	$0.6270	$0.6439
204 Russian Labor ($/kW/yr) (escalated)	$935	$1.0553	$1.0553	$1.4490	$1.8227	$2.1933	$2.5628	$2.9214	$3.4774	$4.0206	$4.5448	$5.0667	$5.5837	$5.7889
205 Russian OOPs ($/kW/yr) (esc., avg.Mat&Lab)	$405	$0.4571	$0.4571	$0.5569	$0.6519	$0.7479	$0.8451	$0.9400	$1.0700	$1.1968	$1.3188	$1.4408	$1.5620	$1.6159
206 Total Fixed O&M ($/kW/y)	$5,475	$6.1795	$6.9808	$7.6015	$8.1777	$8.7826	$9.4083	$10.0130	$10.8561	$11.6746	$12.4534	$13.2392	$14.0223	$14.4296
207														
208	Total 1995	$/MWh												
209 Variable O&M Calculations	000 $	(6600 GWh)												
210 Non-Russian Materials ($/kWh) (duties)	$3,550	$0.5379	$0.00065	$0.00066	$0.00067	$0.00068	$0.00070	$0.00071	$0.00073	$0.00075	$0.00076	$0.00078	$0.00080	$0.00081
211 Non-Russian OOPs ($/kWh)	$225	$0.0341	$0.00003	$0.00003	$0.00004	$0.00004	$0.00004	$0.00004	$0.00004	$0.00004	$0.00004	$0.00004	$0.00004	$0.00004
212 Russian Materials ($/kWh) (escalated)	$760	$0.1152	$0.00012	$0.00012	$0.00013	$0.00014	$0.00015	$0.00015	$0.00016	$0.00016	$0.00017	$0.00017	$0.00018	$0.00018
213 Russian Labor ($/kWh) (escalated)	$35	$0.0053	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00002	$0.00002	$0.00002	$0.00003	$0.00003	$0.00003
214 Russian OOPs ($/kWh) (esc., avg.Mat&Lab)	$115	$0.0174	$0.00002	$0.00002	$0.00002	$0.00003	$0.00003	$0.00004	$0.00004	$0.00005	$0.00005	$0.00005	$0.00006	$0.00006
215 Total Variable O&M ($/kWh)	$4,685	$0.7096	$0.00082	$0.00084	$0.00087	$0.00090	$0.00093	$0.00096	$0.00099	$0.00102	$0.00105	$0.00108	$0.00110	$0.00113
216														
217 **Costs of Production ('000 US$)**														
218 Variable O&M				$0	$0	$78	$1,706	$5,202	$6,239	$6,428	$6,600	$6,781	$6,965	$7,125
219 Fixed O&M				$0	$0	$2,635	$7,056	$9,012	$9,770	$10,507	$11,208	$11,915	$12,620	$12,987
220 Generation Costs				$0	$0	$1,615	$33,102	$73,167	$83,790	$85,717	$87,431	$89,268	$92,054	$94,927
221														
222 *Transmission & Distribution Losses*				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
223 Own Use and Auxilary Use				1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%
224 Total Electricity Available (GWh/yr)				0	0	86	1,811	5,347	6,209	6,209	6,209	6,209	6,209	6,209
225														

ASSUMPTIONS (Input Constant Dollars)	2007 12	2008 13	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25
199 **O&M CALCULATIONS**														
200 Fixed O&M Calculations														
201 Non-Russian Materials ($/kW/yr) (duties)	$6.1880	$6.3179	$6.4506	$6.5861	$6.7244	$6.8656	$7.0098	$7.1570	$7.3073	$7.4607	$7.6174	$7.7774	$7.9407	$8.1074
202 Non-Russian OOPs ($/kW/yr)	$0.3268	$0.3337	$0.3407	$0.3479	$0.3552	$0.3626	$0.3702	$0.3780	$0.3859	$0.3941	$0.4023	$0.4108	$0.4194	$0.4282
203 Russian Materials ($/kW/yr) (escalated)	$0.6611	$0.6788	$0.6970	$0.7156	$0.7357	$0.7563	$0.7775	$0.7992	$0.8215	$0.8444	$0.8679	$0.8920	$0.9167	$0.9421
204 Russian Labor ($/kW/yr) (escalated)	$5.9955	$6.2036	$6.4135	$6.6254	$6.8395	$7.0560	$7.2752	$7.4972	$7.7221	$7.9502	$8.1816	$8.4165	$8.6550	$8.8972
205 Russian OOPs ($/kW/yr) (esc., avg.Mat&Lab)	$1.6704	$1.7254	$1.7811	$1.8374	$1.8951	$1.9536	$2.0130	$2.0733	$2.1345	$2.1968	$2.2601	$2.3246	$2.3901	$2.4569
206 Total Fixed O&M ($/kW/y)	$14.8418	$15.2594	$15.6828	$16.1123	$16.5498	$16.9942	$17.4457	$17.9047	$18.3714	$18.8462	$19.3293	$19.8211	$20.3219	$20.8318
207														
208														
209 Variable O&M Calculations														
210 Non-Russian Materials ($/kWh) (duties)	$0.00063	$0.00065	$0.00067	$0.00068	$0.00090	$0.00092	$0.00094	$0.00096	$0.00098	$0.00100	$0.00102	$0.00104	$0.00107	$0.00109
211 Non-Russian OOPs ($/kWh)	$0.00004	$0.00004	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005	$0.00006	$0.00006	$0.00006
212 Russian Materials ($/kWh) (escalated)	$0.00019	$0.00019	$0.00020	$0.00020	$0.00021	$0.00021	$0.00022	$0.00023	$0.00023	$0.00024	$0.00025	$0.00025	$0.00026	$0.00027
213 Russian Labor ($/kWh) (escalated)	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00004	$0.00004	$0.00004	$0.00004	$0.00004	$0.00004	$0.00004	$0.00004	$0.00004
214 Russian OOPs ($/kWh) (esc., avg.Mat&Lab)	$0.00006	$0.00007	$0.00007	$0.00007	$0.00007	$0.00007	$0.00008	$0.00008	$0.00008	$0.00008	$0.00009	$0.00009	$0.00009	$0.00009
215 Total Variable O&M ($/kWh)	$0.00116	$0.00118	$0.00121	$0.00124	$0.00127	$0.00129	$0.00132	$0.00135	$0.00139	$0.00142	$0.00145	$0.00148	$0.00152	$0.00155
216														
217 **Costs of Production ('000 US$)**														
218 Variable O&M	$7,289	$7,457	$7,627	$7,685	$7,742	$7,798	$7,852	$7,904	$7,954	$8,001	$8,047	$8,090	$8,131	$8,169
219 Fixed O&M	$13,358	$13,733	$14,115	$14,501	$14,895	$15,295	$15,701	$16,114	$16,534	$16,962	$17,396	$17,839	$18,290	$18,749
220 Generation Costs	$97,889	$100,944	$104,095	$105,733	$107,373	$109,012	$110,648	$112,281	$113,908	$115,527	$117,136	$118,732	$120,315	$121,880
221														
222 Transmission & Distribution Losses	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
223 Own Use and Auxiliary Use	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%
224 Total Electricity Available (GWh/yr)	6,209	6,209	6,209	6,116	6,023	5,930	5,837	5,743	5,650	5,557	5,464	5,371	5,278	5,185
225														

253

ASSUMPTIONS (Input Constant Dollars)	2021 26	2022 27	2023 28	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39
199 **O&M CALCULATIONS**														
200 Fixed O&M Calculations														
201 Non-Russian Materials ($/kW/yr) (duties)	$8.2777	$8.4515	$8.6290	$8.8102	$8.9952	$9.1841	$9.3770	$9.5739	$9.7750	$9.9802	$10.1898	$10.4038	$10.6223	$10.8454
202 Non-Russian OOPs ($/kW/yr)	$0.4372	$0.4464	$0.4558	$0.4653	$0.4751	$0.4851	$0.4953	$0.5057	$0.5163	$0.5271	$0.5382	$0.5495	$0.5610	$0.5728
203 Russian Materials ($/kW/yr) (escalated)	$0.9681	$0.9948	$1.0222	$1.0503	$1.0792	$1.1087	$1.1320	$1.1558	$1.1801	$1.2049	$1.2302	$1.2560	$1.2824	$1.3093
204 Russian Labor ($/kW/yr) (escalated)	$9.0841	$9.2749	$9.4696	$9.6685	$9.8715	$10.0788	$10.2905	$10.5066	$10.7272	$10.9525	$11.1825	$11.4173	$11.6571	$11.9019
205 Russian OOPs ($/kW/yr) (esc., avg.Mat&Lab)	$2.5120	$2.5683	$2.6259	$2.6848	$2.7450	$2.8065	$2.8655	$2.9256	$2.9871	$3.0498	$3.1138	$3.1792	$3.2460	$3.3142
206 Total Fixed O&M ($/kW/y)	$21.2790	$21.7359	$22.2025	$22.6791	$23.1660	$23.6633	$24.1602	$24.6676	$25.1856	$25.7145	$26.2545	$26.8059	$27.3688	$27.9435
207														
208														
209 Variable O&M Calculations														
210 Non-Russian Materials ($/kWh) (duties)	$0.00111	$0.00113	$0.00116	$0.00118	$0.00121	$0.00123	$0.00126	$0.00129	$0.00131	$0.00134	$0.00137	$0.00140	$0.00143	$0.00146
211 Non-Russian OOPs ($/kWh)	$0.00006	$0.00006	$0.00006	$0.00006	$0.00006	$0.00007	$0.00007	$0.00007	$0.00007	$0.00007	$0.00007	$0.00007	$0.00008	$0.00008
212 Russian Materials ($/kWh) (escalated)	$0.00027	$0.00028	$0.00029	$0.00030	$0.00031	$0.00031	$0.00032	$0.00033	$0.00033	$0.00034	$0.00035	$0.00036	$0.00036	$0.00037
213 Russian Labor ($/kWh) (escalated)	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005	$0.00006	$0.00006	$0.00006	$0.00006	$0.00006
214 Russian OOPs ($/kWh) (esc., avg.Mat&Lab)	$0.00010	$0.00010	$0.00010	$0.00010	$0.00010	$0.00011	$0.00011	$0.00011	$0.00011	$0.00012	$0.00012	$0.00012	$0.00012	$0.00013
215 Total Variable O&M ($/kWh)	$0.00159	$0.00162	$0.00166	$0.00169	$0.00173	$0.00177	$0.00181	$0.00184	$0.00188	$0.00192	$0.00196	$0.00200	$0.00205	$0.00209
216														
217 **Costs of Production ('000 US$)**														
218 Variable O&M	$8,201	$8,230	$8,256	$8,279	$8,299	$8,316	$8,320	$8,320	$8,317	$8,309	$8,298	$8,283	$8,263	$8,239
219 Fixed O&M	$19,151	$19,562	$19,982	$20,411	$20,849	$21,297	$21,744	$22,201	$22,667	$23,143	$23,629	$24,125	$24,632	$25,149
220 Generation Costs	$123,427	$124,950	$126,449	$127,920	$129,359	$130,763	$132,130	$133,454	$134,732	$135,959	$137,133	$138,247	$139,296	$140,277
221														
222 Transmission & Distribution Losses	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
223 Own Use and Auxillary Use	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%	1.56%
224 Total Electricity Available (GWh/yr)	5,091	4,998	4,905	4,812	4,719	4,626	4,533	4,439	4,346	4,253	4,160	4,067	3,974	3,881
225														

254

ASSUMPTIONS (Input Constant Dollars)	Project Year	1995 0	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11
226 **PARAMETERS FOR SOLVER ALGORITHM**													
227													
228 **Required IRR's**													
229 Russian Ownership Group FIRR		15.0%											
230 Non-Russian Investor(s) FIRR		#VALUE!											
231 Weighted Average FIRR		15.0%											
232													
233 **Equity Contributions**	Percent of Total		Total Amount		**Debt**								
234 Russian Ownership Group	100.00%		264,011		WB	500,000							
235 Non-Russian Investor(s)	0.00%		0		ECA	0							
236 Total Equity Contributions			264,011										
237				as % of Total Capital									
238 **Equity Returns**	Percent of Total			WB Loan	61.56%	65.44%							
239 Russian Ownership Group	100.00%			ECA Loan	0.00%	0.00%							
240 Non-Russian Investor(s)	0.00%			Equity	34.56%	34.56%							
241					96.12%	100.00%							
242 **Miscellaneous Parameters**	**Color Code**												
243 Equity Contribution (Plug)	Target	264,011	19,854	83,233	102,193	78,732	0	0					
244 Margin (Independent Variable)	Ind. Variables		0.37417	0.02095	0.09277	-0.06497	0.00000	0.00%					
245 Additions to Contingency Fund (set to --> 0)	Constraint		0	0	0	0	0	0					
246 Funds Available to Equity Shareholders	Outputs		0	0	0	0	12,287	11,403					
247	Miscellaneous												
248 **Pricing by Tariff Structure**													
249 Option 1: Average Tariff ($/kWh)		0.0302	0.0308	0.0313	0.0319	0.0327	0.0334	0.0342	0.0350	0.0357	0.0365	0.0372	0.0380
250 Option 2a: Capacity Charge ($/kW/yr)		92.00	93.84	95.34	97.34	99.68	101.87	104.42	106.82	108.96	111.25	113.58	115.97
251 Option 2b: Energy Charge ($/kWh)		0.0138			0.0213	0.0208	0.0159	0.0157	0.0161	0.0164	0.0168	0.0173	0.0178
252 Energy Charge includes recovery of cost of													
253 fuel, variable O&M, and allowance for other													
254 fees equal to include an additional -->	10%												
255 Selection "1" or "2" for one of the options		1											

257

ASSUMPTIONS (Input Constant Dollars)	2007 12	2008 13	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25
226 **PARAMETERS FOR SOLVER ALGORITHM**														
227														
228 **Required IRR's**														
229 Russian Ownership Group FIRR														
230 Non-Russian Investor(s) FIRR														
231 Weighted Average FIRR														
232														
233 **Equity Contributions**														
234 Russian Ownership Group														
235 Non-Russian Investor(s)														
236 Total Equity Contributions														
237														
238 **Equity Returns**														
239 Russian Ownership Group														
240 Non-Russian Investor(s)														
241														
242 **Miscellaneous Parameters**														
243 Equity Contribution (Plug)														
244 Margin (Independent Variable)														
245 *Additions to Contingency Fund (set to --> 0)*														
246 Funds Available to Equity Shareholders														
247														
248 **Pricing by Tariff Structure**														
249 Option 1: Average Tariff ($/kWh)	0.0388	0.0396	0.0405	0.0413	0.0422	0.0431	0.0440	0.0449	0.0458	0.0468	0.0478	0.0488	0.0498	0.0509
250 Option 2a: Capacity Charge ($/kW/yr)	118.40	120.89	123.43	126.02	128.67	131.37	134.13	136.94	139.82	142.76	145.75	148.81	151.94	155.13
251 Option 2b: Energy Charge ($/kWh)	0.0183	0.0189	0.0195	0.0201	0.0207	0.0213	0.0220	0.0227	0.0234	0.0241	0.0248	0.0256	0.0264	0.0272
252 Energy Charge includes recovery of cost of														
253 fuel, variable O&M, and allowance for other														
254 fees equal to include an additional --->														
255 Selection "1" or "2" for one of the options														

256

ASSUMPTIONS (Input Constant Dollars)	2021 26	2022 27	2023 28	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39
226 **PARAMETERS FOR SOLVER ALGORITHM**														
227														
228 **Required IRR's**														
229 Russian Ownership Group FIRR														
230 Non-Russian Investor(s) FIRR														
231 Weighted Average FIRR														
232														
233 **Equity Contributions**														
234 Russian Ownership Group														
235 Non-Russian Investor(s)														
236 Total Equity Contributions														
237														
238 **Equity Returns**														
239 Russian Ownership Group														
240 Non-Russian Investor(s)														
241														
242 **Miscellaneous Parameters**														
243 Equity Contribution (Plug)														
244 Margin (Independent Variable)														
245 Additions to Contingency Fund (set to --> 0)														
246 Funds Available to Equity Shareholders														
247														
248 **Pricing by Tariff Structure**														
249 Option 1: Average Tariff ($/kWh)	0.0519	0.0530	0.0541	0.0553	0.0564	0.0576	0.0588	0.0601	0.0613	0.0626	0.0639	0.0653	0.0666	0.0680
250 Option 2a: Capacity Charge ($/kW/yr)	158.39	161.71	165.11	168.58	172.12	175.73	179.42	183.19	187.04	190.96	194.97	199.07	203.25	207.52
251 Option 2b: Energy Charge ($/kWh)	0.0280	0.0289	0.0297	0.0306	0.0316	0.0326	0.0336	0.0346	0.0356	0.0367	0.0379	0.0390	0.0402	0.0414
252 *Energy Charge includes recovery of cost of*														
253 *fuel, variable O&M, and allowance for other*														
254 *fees equal to include an additional -->*														
255 *Selection "1" or "2" for one of the options*														

253

Base Project Cost	Russian					Non-Russian			Total
'000 1995 US dollars	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	
Civil Works	0	9,092	7,883	0	16,975	0	0	0	16,975
Combustion Turbine	0	0	440	0	440	120,000	0	120,000	120,440
HRSG	0	0	1,760	0	1,760	34,500	0	34,500	36,260
Steam Turbines	0	0	165	0	165	27,000	0	27,000	27,165
Distributed Control System	0	0	0	0	0	2,900	0	2,900	2,900
Mechanical Package	20,496	11,205	5,137	0	36,838	26,000	0	26,000	62,838
Electrical Package	14,980	7,545	4,718	0	27,243	0	0	0	27,243
Switchyard	3,200	1,440	6,400	0	11,040	29,818	0	29,818	40,858
Engineering & Project Mgmt.	0	0	0	29,010	29,010	0	53,850	53,850	82,860
Subtotal Generation Plant	38,676	29,282	26,503	29,010	123,471	240,218	53,850	294,068	417,539
Transmission Line	6,545	20,545	14,000	4,545	45,636	20,091	0	20,091	65,727
Gas Pipeline	0	0	9,400	3,500	12,900	25,100	0	25,100	38,000
Total Project Costs	45,221	49,827	49,903	37,055	182,007	285,409	53,850	339,259	**521,266**

Scenario Matrix	Russian				*Non-Russian*	
Is each component part of project cost?	Equipment	Material	Labor	Indirect	Equipment	Indirect
Civil Works	yes	yes	yes	yes	yes	yes
Combustion Turbine	yes	yes	yes	yes	yes	yes
HRSG	yes	yes	yes	yes	yes	yes
Steam Turbines	yes	yes	yes	yes	yes	yes
Distributed Control System	yes	yes	yes	yes	yes	yes
Mechanical Package	yes	yes	yes	yes	yes	yes
Electrical Package	yes	yes	yes	yes	yes	yes
Switchyard	yes	yes	yes	yes	yes	yes
Engineering & Project Mgmt.	yes	yes	yes	yes	yes	yes
Transmission Line	no	no	no	no	no	no
Gas Pipeline	no	no	no	no	no	no

Base Project Scenario	Russian					Non-Russian			Total
'000 1995 US dollars	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	
Civil Works	0	9,092	7,883	0	16,975	0	0	0	16,975
Combustion Turbine	0	0	440	0	440	120,000	0	120,000	120,440
HRSG	0	0	1,760	0	1,760	34,500	0	34,500	36,260
Steam Turbines	0	0	165	0	165	27,000	0	27,000	27,165
Distributed Control System	0	0	0	0	0	2,900	0	2,900	2,900
Mechanical Package	20,496	11,205	5,137	0	36,838	26,000	0	26,000	62,838
Electrical Package	14,980	7,545	4,718	0	27,243	0	0	0	27,243
Switchyard	3,200	1,440	6,400	0	11,040	29,818	0	29,818	40,858
Engineering & Project Mgmt.	0	0	0	29,010	29,010	0	53,850	53,850	82,860
Subtotal Generation Plant	38,676	29,282	26,503	29,010	123,471	240,218	53,850	294,068	417,539
Transmission Line	0	0	0	0	0	0	0	0	0
Gas Pipeline	0	0	0	0	0	0	0	0	0
Total Project Costs	38,676	29,282	26,503	29,010	123,471	240,218	53,850	294,068	**417,539**

Duties & Excise Taxes =	20%

Duties & Excise Taxes, Matrix	Russian				Non-Russian	
Do duties/taxes apply to each component?	Equipment	Material	Labor	Indirect	Equipment	Indirect
Civil Works	no	no	no	no	yes	yes
Combustion Turbine	no	no	no	no	yes	yes
HRSG	no	no	no	no	yes	yes
Steam Turbines	no	no	no	no	yes	yes
Distributed Control System	no	no	no	no	yes	yes
Mechanical Package	no	no	no	no	yes	yes
Electrical Package	no	no	no	no	yes	yes
Switchyard	no	no	no	no	yes	yes
Engineering & Project Mgmt.	no	no	no	no	yes	yes
Transmission Line	no	no	no	no	yes	yes
Gas Pipeline	no	no	no	no	yes	yes

Duties & Excise Taxes, Calculated	Russian					Non-Russian			
'000 1995 US dollars	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
Civil Works	0	0	0	0	0	0	0	0	0
Combustion Turbine	0	0	0	0	0	24,000	0	24,000	24,000
HRSG	0	0	0	0	0	6,900	0	6,900	6,900
Steam Turbines	0	0	0	0	0	5,400	0	5,400	5,400
Distributed Control System	0	0	0	0	0	580	0	580	580
Mechanical Package	0	0	0	0	0	5,200	0	5,200	5,200
Electrical Package	0	0	0	0	0	0	0	0	0
Switchyard	0	0	0	0	0	5,964	0	5,964	5,964
Engineering & Project Mgmt.	0	0	0	0	0	0	10,770	10,770	10,770
Subtotal Generation Plant	0	0	0	0	0	48,044	10,770	58,814	58,814
Transmission Line	0	0	0	0	0	0	0	0	0
Gas Pipeline	0	0	0	0	0	0	0	0	0
Total Project Duties & Taxes	0	0	0	0	0	48,044	10,770	58,814	58,814

Physical Contingencies*	25%	Russian	10%	Non-Russian

Contingencies, Matrix	Russian				Non-Russian	
Do contengencies apply to each component?	Equipment	Material	Labor	Indirect	Equipment	Indirect
Civil Works	yes	yes	yes	yes	yes	yes
Combustion Turbine	yes	yes	yes	yes	yes	yes
HRSG	yes	yes	yes	yes	yes	yes
Steam Turbines	yes	yes	yes	yes	yes	yes
Distributed Control System	yes	yes	yes	yes	yes	yes
Mechanical Package	yes	yes	yes	yes	yes	yes
Electrical Package	yes	yes	yes	yes	yes	yes
Switchyard	yes	yes	yes	yes	yes	yes
Engineering & Project Mgmt.	yes	yes	yes	yes	yes	yes
Transmission Line	yes	yes	yes	yes	yes	yes
Gas Pipeline	yes	yes	yes	yes	yes	yes

Contingencies, Calculated	Russian					Non-Russian			Total
'000 1995 US dollars	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	
Civil Works	0	2,273	1,971	0	4,244	0	0	0	4,244
Combustion Turbine	0	0	110	0	110	14,400	0	14,400	14,510
HRSG	0	0	440	0	440	4,140	0	4,140	4,580
Steam Turbines	0	0	41	0	41	3,240	0	3,240	3,281
Distributed Control System	0	0	0	0	0	348	0	348	348
Mechanical Package	5,124	2,801	1,284	0	9,210	3,120	0	3,120	12,330
Electrical Package	3,745	1,886	1,180	0	6,811	0	0	0	6,811
Switchyard	800	360	1,600	0	2,760	3,578	0	3,578	6,338
Engineering & Project Mgmt.	0	0	0	7,253	7,253	0	6,462	6,462	13,715
Subtotal Generation Plant	9,669	7,321	6,626	7,253	30,868	28,826	6,462	35,288	66,156
Transmission Line	0	0	0	0	0	0	0	0	0
Gas Pipeline	0	0	0	0	0	0	0	0	0
Total Physical Contingencies	9,669	7,321	6,626	7,253	30,868	28,826	6,462	35,288	66,156

Expenditure Profile	Project Year					
	1	2	3	4	5	Total
Civil Works	5%	22%	33%	28%	12%	100%
Combustion Turbine	5%	22%	33%	28%	12%	100%
HRSG	5%	22%	33%	28%	12%	100%
Steam Turbines	5%	22%	33%	28%	12%	100%
Distributed Control System	5%	22%	33%	28%	12%	100%
Mechanical Package	5%	22%	33%	28%	12%	100%
Electrical Package	5%	22%	33%	28%	12%	100%
Switchyard	5%	22%	33%	28%	12%	100%
Engineering & Project Mgmt.	5%	22%	33%	28%	12%	100%
Transmission Line	30%	40%	15%	15%	0%	100%
Gas Pipeline	40%	60%	0%	0%	0%	100%

Escalation Matrix	Russian vs. U.S. Real Escalation			
Is each component to be escalated?	Equipment	Material	Labor	Indirect
Civil Works	yes	yes	yes	yes
Combustion Turbine	yes	yes	yes	yes
HRSG	yes	yes	yes	yes
Steam Turbines	yes	yes	yes	yes
Distributed Control System	yes	yes	yes	yes
Mechanical Package	yes	yes	yes	yes
Electrical Package	yes	yes	yes	yes
Switchyard	yes	yes	yes	yes
Engineering & Project Mgmt.	yes	yes	yes	yes
Transmission Line	yes	yes	yes	yes
Gas Pipeline	yes	yes	yes	yes

Real Escalation Factors	Project Year					
	0	1	2	3	4	5
RUSSIAN VS. U.S. COSTS						
Material	70.0%	73.0%	76.0%	79.0%	82.0%	85.0%
Equipment	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%
Labor cost	10.0%	14.0%	18.0%	22.0%	26.0%	30.0%
Labor productivity	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%
Labor -- total cost	20.0%	26.9%	33.3%	39.3%	44.8%	50.0%
RUSSIAN VS. U.S. ESCALATION FACTORS						
Equipment	1.00	1.04	1.08	1.12	1.16	1.20
Material	1.00	1.04	1.09	1.13	1.17	1.21
Labor	1.00	1.35	1.67	1.96	2.24	2.50
Average of Labor & Material (Indirect)	1.00	1.19	1.38	1.55	1.71	1.86

160										
161	**Full Project Costs, w/o VAT**	**1996**								
162	Includes physical contingencies, duties &	Russian					Non-Russian			
163	excise taxes, and real escalation	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
164	Civil Works	0	645	691	0	1,336	0	0	0	1,336
165	Combustion Turbine	0	0	39	0	39	8,693	0	8,693	8,732
166	HRSG	0	0	154	0	154	2,499	0	2,499	2,653
167	Steam Turbines	0	0	14	0	14	1,956	0	1,956	1,970
168	Distributed Control System	0	0	0	0	0	210	0	210	210
169	Mechanical Package	1,451	795	450	0	2,696	1,883	0	1,883	4,580
170	Electrical Package	1,061	535	413	0	2,009	0	0	0	2,009
171	Switchyard	227	102	561	0	889	2,160	0	2,160	3,049
172	Engineering & Project Mgmt.	0	0	0	2,300	2,300	0	3,901	3,901	6,201
173	Subtotal Generation Plant	2,738	2,078	2,322	2,300	9,437	17,402	3,901	21,303	30,740
174	Transmission Line	0	0	0	0	0	0	0	0	0
175	Gas Pipeline	0	0	0	0	0	0	0	0	0
176	Total Project Costs, w/o VAT	2,738	2,078	2,322	2,300	9,437	17,402	3,901	21,303	30,740
177	**Full Project Costs, w/o VAT**	**1997**								
178	Includes physical contingencies, duties &	Russian					Non-Russian			
179	excise taxes, and real escalation	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
180	Civil Works	0	2,715	3,378	0	6,093	0	0	0	6,093
181	Combustion Turbine	0	0	189	0	189	35,415	0	35,415	35,604
182	HRSG	0	0	754	0	754	10,182	0	10,182	10,936
183	Steam Turbines	0	0	71	0	71	7,968	0	7,968	8,039
184	Distributed Control System	0	0	0	0	0	856	0	856	856
185	Mechanical Package	6,095	3,346	2,201	0	11,642	7,673	0	7,673	19,316
186	Electrical Package	4,454	2,253	2,022	0	8,730	0	0	0	8,730
187	Switchyard	956	617	2,327	0	3,900	8,800	0	8,800	12,700
188	Engineering & Project Mgmt.	0	0	0	10,548	10,548	0	15,893	15,893	26,440
189	Subtotal Generation Plant	11,505	8,932	10,942	10,548	41,926	70,894	15,893	86,787	128,713
190	Transmission Line	0	0	0	0	0	0	0	0	0
191	Gas Pipeline	0	0	0	0	0	0	0	0	0
192	Total Project Costs, w/o VAT	11,505	8,932	10,942	10,548	41,926	70,894	15,893	86,787	128,713

193	**Full Project Costs, w/o VAT**	**1998**								
194	Includes physical contingencies, duties &	Russian					Non-Russian			
195	excise taxes, and real escalation	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
196	Civil Works	0	4,076	5,676	0	9,752	0	0	0	9,752
197	Combustion Turbine	0	0	317	0	317	51,512	0	51,512	51,829
198	HRSG	0	0	1,267	0	1,267	14,810	0	14,810	16,077
199	Steam Turbines	0	0	119	0	119	11,590	0	11,590	11,709
200	Distributed Control System	0	0	0	0	0	1,245	0	1,245	1,245
201	Mechanical Package	9,131	5,023	3,699	0	17,854	11,161	0	11,161	29,015
202	Electrical Package	6,674	3,383	3,397	0	13,454	0	0	0	13,454
203	Switchyard	1,426	646	4,609	0	6,680	12,800	0	12,800	19,480
204	Engineering & Project Mgmt.	0	0	0	16,948	16,948	0	23,116	23,116	40,063
205	Subtotal Generation Plant	17,231	13,127	19,084	16,948	66,391	103,117	23,116	126,233	192,623
206	Transmission Line	0	0	0	0	0	0	0	0	0
207	Gas Pipeline	0	0	0	0	0	0	0	0	0
208	Total Project Costs, w/o VAT	17,231	13,127	19,084	16,948	66,391	103,117	23,116	126,233	192,623
209	**Full Project Costs, w/o VAT**	**1999**								
210	Includes physical contingencies, duties &	Russian					Non-Russian			
211	excise taxes, and real escalation	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
212	Civil Works	0	3,612	5,489	0	9,100	0	0	0	9,100
213	Combustion Turbine	0	0	306	0	306	44,268	0	44,268	44,574
214	HRSG	0	0	1,225	0	1,225	12,727	0	12,727	13,952
215	Steam Turbines	0	0	115	0	115	9,960	0	9,960	10,075
216	Distributed Control System	0	0	0	0	0	1,070	0	1,070	1,070
217	Mechanical Package	8,077	4,451	3,577	0	16,104	9,591	0	9,591	25,696
218	Electrical Package	5,903	2,997	3,285	0	12,185	0	0	0	12,185
219	Switchyard	1,261	572	4,456	0	6,289	11,000	0	11,000	17,289
220	Engineering & Project Mgmt.	0	0	0	15,861	15,861	0	19,865	19,865	35,727
221	Subtotal Generation Plant	15,240	11,632	18,453	15,861	61,187	88,617	19,865	108,482	169,669
222	Transmission Line	0	0	0	0	0	0	0	0	0
223	Gas Pipeline	0	0	0	0	0	0	0	0	0
224	Total Project Costs, w/o VAT	15,240	11,632	18,453	15,861	61,187	88,617	19,865	108,482	169,669

263

225	**Full Project Costs, w/o VAT**	**2000**								
226	Includes physical contingencies, duties &	Russian					Non-Russian			
227	taxes, and real escalation	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
228	Civil Works	0	1,556	2,534	0	4,089	0	0	0	4,089
229	Combustion Turbine	0	0	141	0	141	18,512	0	18,512	18,654
230	HRSG	0	0	566	0	566	5,322	0	5,322	5,888
231	Steam Turbines	0	0	53	0	53	4,165	0	4,165	4,218
232	Distributed Control System	0	0	0	0	0	447	0	447	447
233	Mechanical Package	3,473	1,918	1,651	0	7,042	4,011	0	4,011	11,053
234	Electrical Package	2,539	1,291	1,516	0	5,346	0	0	0	5,346
235	Switchyard	542	246	2,057	0	2,846	4,600	0	4,600	7,446
236	Engineering & Project Mgmt.	0	0	0	7,144	7,144	0	8,307	8,307	15,451
237	Subtotal Generation Plant	6,554	5,011	8,518	7,144	27,227	37,058	8,307	45,365	72,592
238	Transmission Line	0	0	0	0	0	0	0	0	0
239	Gas Pipeline	0	0	0	0	0	0	0	0	0
240	Total Project Costs, w/o VAT	6,554	5,011	8,518	7,144	27,227	37,058	8,307	45,365	72,592
241	**Full Project Costs, w/o VAT**	**Total of 5 Years**								
242	Includes physical contingencies, duties &	Russian					Non-Russian			
243	excise taxes, and real escalation	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
244	Civil Works	0	12,604	17,767	0	30,371	0	0	0	30,371
245	Combustion Turbine	0	0	992	0	992	158,400	0	158,400	159,392
246	HRSG	0	0	3,967	0	3,967	45,540	0	45,540	49,507
247	Steam Turbines	0	0	372	0	372	35,640	0	35,640	36,012
248	Distributed Control System	0	0	0	0	0	3,828	0	3,828	3,828
249	Mechanical Package	28,227	15,533	11,578	0	55,338	34,320	0	34,320	89,658
250	Electrical Package	20,630	10,459	10,634	0	41,724	0	0	0	41,724
251	Switchyard	4,411	2,183	14,009	0	20,604	39,360	0	39,360	59,963
252	Engineering & Project Mgmt.	0	0	0	52,800	52,800	0	71,082	71,082	123,882
253	Subtotal Generation Plant	53,268	40,780	59,319	52,800	206,168	317,088	71,082	388,170	594,337
254	Transmission Line	0	0	0	0	0	0	0	0	0
255	Gas Pipeline	0	0	0	0	0	0	0	0	0
256	Total Project Costs, w/o VAT	53,268	40,780	59,319	52,800	206,168	317,088	71,082	388,170	594,337
257										

258		
259	**VAT & Special Tax =**	21.5%
260	**Year of Registration**	1994
261		

262	**VAT & Special Tax Matrix**	Russian				Non-Russian	
263	Do VAT/special taxes apply to each component?	Equipment	Material	Labor	Indirect	Equipment	Indirect
264	Civil Works	yes	yes	no	yes	yes	yes
265	Combustion Turbine	yes	yes	no	yes	yes	yes
266	HRSG	yes	yes	no	yes	yes	yes
267	Steam Turbines	yes	yes	no	yes	yes	yes
268	Distributed Control System	yes	yes	no	yes	yes	yes
269	Mechanical Package	yes	yes	no	yes	yes	yes
270	Electrical Package	yes	yes	no	yes	yes	yes
271	Switchyard	yes	yes	no	yes	yes	yes
272	Engineering & Project Mgmt.	yes	yes	no	yes	yes	yes
273	Transmission Line	yes	yes	no	yes	yes	yes
274	Gas Pipeline	yes	yes	no	yes	yes	yes
275							

276										
277	**VAT/Special Tax, Calculated**	**1996**								
278		Russian					Non-Russian			
279		Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
280	Civil Works	0	139	0	0	139	0	0	0	139
281	Combustion Turbine	0	0	0	0	0	1,869	0	1,869	1,869
282	HRSG	0	0	0	0	0	537	0	537	537
283	Steam Turbines	0	0	0	0	0	421	0	421	421
284	Distributed Control System	0	0	0	0	0	45	0	45	45
285	Mechanical Package	312	171	0	0	483	405	0	405	888
286	Electrical Package	228	115	0	0	343	0	0	0	343
287	Switchyard	49	22	0	0	71	464	0	464	535
288	Engineering & Project Mgmt.	0	0	0	494	494	0	839	839	1,333
289	Subtotal Generation Plant	589	447	0	494	1,530	3,741	839	4,580	6,110
290	Transmission Line	0	0	0	0	0	0	0	0	0
291	Gas Pipeline	0	0	0	0	0	0	0	0	0
292	Total VAT/Special Tax	589	447	0	494	1,530	3,741	839	4,580	6,110
293	**VAT/Special Tax, Calculated**	**1997**								
294		Russian					Non-Russian			
295		Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
296	Civil Works	0	584	0	0	584	0	0	0	584
297	Combustion Turbine	0	0	0	0	0	7,614	0	7,614	7,614
298	HRSG	0	0	0	0	0	2,189	0	2,189	2,189
299	Steam Turbines	0	0	0	0	0	1,713	0	1,713	1,713
300	Distributed Control System	0	0	0	0	0	184	0	184	184
301	Mechanical Package	1,310	719	0	0	2,030	1,650	0	1,650	3,680
302	Electrical Package	958	484	0	0	1,442	0	0	0	1,442
303	Switchyard	205	133	0	0	338	1,892	0	1,892	2,230
304	Engineering & Project Mgmt.	0	0	0	2,268	2,268	0	3,417	3,417	5,685
305	Subtotal Generation Plant	2,474	1,920	0	2,268	6,662	15,242	3,417	18,659	25,321
306	Transmission Line	0	0	0	0	0	0	0	0	0
307	Gas Pipeline	0	0	0	0	0	0	0	0	0
308	Total VAT/Special Tax	2,474	1,920	0	2,268	6,662	15,242	3,417	18,659	25,321

		1998								
309	**VAT/Special Tax, Calculated**									
310		Russian					Non-Russian			
311		Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
312	Civil Works	0	876	0	0	876	0	0	0	876
313	Combustion Turbine	0	0	0	0	0	11,075	0	11,075	11,075
314	HRSG	0	0	0	0	0	3,184	0	3,184	3,184
315	Steam Turbines	0	0	0	0	0	2,492	0	2,492	2,492
316	Distributed Control System	0	0	0	0	0	268	0	268	268
317	Mechanical Package	1,963	1,080	0	0	3,043	2,400	0	2,400	5,443
318	Electrical Package	1,435	727	0	0	2,162	0	0	0	2,162
319	Switchyard	307	139	0	0	445	2,752	0	2,752	3,197
320	Engineering & Project Mgmt.	0	0	0	3,644	3,644	0	4,970	4,970	8,614
321	Subtotal Generation Plant	3,705	2,822	0	3,644	10,171	22,170	4,970	27,140	37,311
322	Transmission Line	0	0	0	0	0	0	0	0	0
323	Gas Pipeline	0	0	0	0	0	0	0	0	0
324	Total VAT/Special Tax	3,705	2,822	0	3,644	10,171	22,170	4,970	27,140	37,311
325	**VAT/Special Tax, Calculated**	1999								
326		Russian					Non-Russian			
327		Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
328	Civil Works	0	777	0	0	777	0	0	0	777
329	Combustion Turbine	0	0	0	0	0	9,518	0	9,518	9,518
330	HRSG	0	0	0	0	0	2,736	0	2,736	2,736
331	Steam Turbines	0	0	0	0	0	2,141	0	2,141	2,141
332	Distributed Control System	0	0	0	0	0	230	0	230	230
333	Mechanical Package	1,736	957	0	0	2,693	2,062	0	2,062	4,756
334	Electrical Package	1,269	644	0	0	1,914	0	0	0	1,914
335	Switchyard	271	123	0	0	394	2,365	0	2,365	2,759
336	Engineering & Project Mgmt.	0	0	0	3,410	3,410	0	4,271	4,271	7,681
337	Subtotal Generation Plant	3,277	2,501	0	3,410	9,188	19,053	4,271	23,324	32,511
338	Transmission Line	0	0	0	0	0	0	0	0	0
339	Gas Pipeline	0	0	0	0	0	0	0	0	0
340	Total VAT/Special Tax	3,277	2,501	0	3,410	9,188	19,053	4,271	23,324	32,511

341	**VAT/Special Tax, Calculated**	**2000**								
342		Russian					Non-Russian			
343		Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
344	Civil Works	0	335	0	0	335	0	0	0	335
345	Combustion Turbine	0	0	0	0	0	3,980	0	3,980	3,980
346	HRSG	0	0	0	0	0	1,144	0	1,144	1,144
347	Steam Turbines	0	0	0	0	0	896	0	896	896
348	Distributed Control System	0	0	0	0	0	96	0	96	96
349	Mechanical Package	747	412	0	0	1,159	862	0	862	2,021
350	Electrical Package	546	278	0	0	823	0	0	0	823
351	Switchyard	117	53	0	0	170	989	0	989	1,159
352	Engineering & Project Mgmt.	0	0	0	1,536	1,536	0	1,786	1,786	3,322
353	Subtotal Generation Plant	1,409	1,077	0	1,536	4,022	7,967	1,786	9,754	13,776
354	Transmission Line	0	0	0	0	0	0	0	0	0
355	Gas Pipeline	0	0	0	0	0	0	0	0	0
356	Total VAT/Special Tax	1,409	1,077	0	1,536	4,022	7,967	1,786	9,754	13,776
357	**VAT/Special Tax, Calculated**	**Total of 5 Years**								
358		Russian					Non-Russian			
359		Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
360	Civil Works	0	2,710	0	0	2,710	0	0	0	2,710
361	Combustion Turbine	0	0	0	0	0	34,056	0	34,056	34,056
362	HRSG	0	0	0	0	0	9,791	0	9,791	9,791
363	Steam Turbines	0	0	0	0	0	7,663	0	7,663	7,663
364	Distributed Control System	0	0	0	0	0	823	0	823	823
365	Mechanical Package	6,069	3,340	0	0	9,408	7,379	0	7,379	16,787
366	Electrical Package	4,436	2,249	0	0	6,684	0	0	0	6,684
367	Switchyard	948	469	0	0	1,418	8,462	0	8,462	9,880
368	Engineering & Project Mgmt.	0	0	0	11,352	11,352	0	15,283	15,283	26,635
369	Subtotal Generation Plant	11,453	8,768	0	11,352	31,573	68,174	15,283	83,456	115,029
370	Transmission Line	0	0	0	0	0	0	0	0	0
371	Gas Pipeline	0	0	0	0	0	0	0	0	0
372	Total VAT/Special Tax	11,453	8,768	0	11,352	31,573	68,174	15,283	83,456	**115,029**
373										

Full Project Costs, w VAT	1996								
Includes VAT and Special Tax	Russian					Non-Russian			
	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
Civil Works	0	784	691	0	1,474	0	0	0	1,474
Combustion Turbine	0	0	39	0	39	10,562	0	10,562	10,601
HRSG	0	0	154	0	154	3,037	0	3,037	3,191
Steam Turbines	0	0	14	0	14	2,376	0	2,376	2,391
Distributed Control System	0	0	0	0	0	255	0	255	255
Mechanical Package	1,763	966	450	0	3,179	2,288	0	2,288	5,467
Electrical Package	1,289	650	413	0	2,352	0	0	0	2,352
Switchyard	275	124	561	0	960	2,624	0	2,624	3,584
Engineering & Project Mgmt.	0	0	0	2,794	2,794	0	4,740	4,740	7,534
Subtotal Generation Plant	3,327	2,524	2,322	2,794	10,967	21,143	4,740	25,883	36,850
Transmission Line	0	0	0	0	0	0	0	0	0
Gas Pipeline	0	0	0	0	0	0	0	0	0
Total Project Costs, w VAT	3,327	2,524	2,322	2,794	10,967	21,143	4,740	25,883	36,850
Full Project Costs, w VAT	1997								
Includes VAT and Special Tax	Russian					Non-Russian			
	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
Civil Works	0	3,299	3,378	0	6,677	0	0	0	6,677
Combustion Turbine	0	0	189	0	189	43,029	0	43,029	43,218
HRSG	0	0	754	0	754	12,371	0	12,371	13,125
Steam Turbines	0	0	71	0	71	9,682	0	9,682	9,752
Distributed Control System	0	0	0	0	0	1,040	0	1,040	1,040
Mechanical Package	7,405	4,066	2,201	0	13,672	9,323	0	9,323	22,995
Electrical Package	5,412	2,738	2,022	0	10,172	0	0	0	10,172
Switchyard	1,161	750	2,327	0	4,238	10,692	0	10,692	14,930
Engineering & Project Mgmt.	0	0	0	12,815	12,815	0	19,309	19,309	32,125
Subtotal Generation Plant	13,978	10,852	10,942	12,815	48,587	86,137	19,309	105,446	154,034
Transmission Line	0	0	0	0	0	0	0	0	0
Gas Pipeline	0	0	0	0	0	0	0	0	0
Total Project Costs, w VAT	13,978	10,852	10,942	12,815	48,587	86,137	19,309	105,446	154,034

		1998								
407	**Full Project Costs, w VAT**	1998								
408	Includes VAT and Special Tax	Russian					Non-Russian			
409		Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
410	Civil Works	0	4,952	5,676	0	10,629	0	0	0	10,629
411	Combustion Turbine	0	0	317	0	317	62,587	0	62,587	62,904
412	HRSG	0	0	1,267	0	1,267	17,994	0	17,994	19,261
413	Steam Turbines	0	0	119	0	119	14,082	0	14,082	14,201
414	Distributed Control System	0	0	0	0	0	1,513	0	1,513	1,513
415	Mechanical Package	11,095	6,103	3,699	0	20,897	13,560	0	13,560	34,458
416	Electrical Package	8,109	4,110	3,397	0	15,616	0	0	0	15,616
417	Switchyard	1,732	784	4,609	0	7,125	15,552	0	15,552	22,677
418	Engineering & Project Mgmt.	0	0	0	20,591	20,591	0	28,086	28,086	48,677
419	Subtotal Generation Plant	20,936	15,950	19,084	20,591	76,561	125,287	28,086	153,373	229,934
420	Transmission Line	0	0	0	0	0	0	0	0	0
421	Gas Pipeline	0	0	0	0	0	0	0	0	0
422	Total Project Costs, w VAT	20,936	15,950	19,084	20,591	76,561	125,287	28,086	153,373	229,934
423	**Full Project Costs, w VAT**	1999								
424	Includes VAT and Special Tax	Russian					Non-Russian			
425		Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
426	Civil Works	0	4,388	5,489	0	9,877	0	0	0	9,877
427	Combustion Turbine	0	0	306	0	306	53,786	0	53,786	54,092
428	HRSG	0	0	1,225	0	1,225	15,463	0	15,463	16,689
429	Steam Turbines	0	0	115	0	115	12,102	0	12,102	12,217
430	Distributed Control System	0	0	0	0	0	1,300	0	1,300	1,300
431	Mechanical Package	9,813	5,408	3,577	0	18,798	11,654	0	11,654	30,451
432	Electrical Package	7,172	3,642	3,285	0	14,099	0	0	0	14,099
433	Switchyard	1,532	695	4,456	0	6,683	13,365	0	13,365	20,048
434	Engineering & Project Mgmt.	0	0	0	19,272	19,272	0	24,136	24,136	43,408
435	Subtotal Generation Plant	18,517	14,133	18,453	19,272	70,375	107,669	24,136	131,805	202,180
436	Transmission Line	0	0	0	0	0	0	0	0	0
437	Gas Pipeline	0	0	0	0	0	0	0	0	0
438	Total Project Costs, w VAT	18,517	14,133	18,453	19,272	70,375	107,669	24,136	131,805	202,180

439	**Full Project Costs, w VAT**	**2000**								
440	Includes VAT and Special Tax	Russian					Non-Russian			
441		Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
442	Civil Works	0	1,890	2,534	0	4,424	0	0	0	4,424
443	Combustion Turbine	0	0	141	0	141	22,492	0	22,492	22,634
444	HRSG	0	0	566	0	566	6,467	0	6,467	7,032
445	Steam Turbines	0	0	53	0	53	5,061	0	5,061	5,114
446	Distributed Control System	0	0	0	0	0	544	0	544	544
447	Mechanical Package	4,220	2,330	1,651	0	8,201	4,873	0	4,873	13,074
448	Electrical Package	3,084	1,569	1,516	0	6,169	0	0	0	6,169
449	Switchyard	659	299	2,057	0	3,015	5,589	0	5,589	8,604
450	Engineering & Project Mgmt.	0	0	0	8,680	8,680	0	10,093	10,093	18,773
451	Subtotal Generation Plant	7,963	6,088	8,518	8,680	31,250	45,026	10,093	55,119	86,369
452	Transmission Line	0	0	0	0	0	0	0	0	0
453	Gas Pipeline	0	0	0	0	0	0	0	0	0
454	Total Project Costs, w VAT	7,963	6,088	8,518	8,680	31,250	45,026	10,093	55,119	86,369
455	**Full Project Costs, w VAT**	**Total of 5 Years**								
456	Includes VAT and Special Tax	Russian					Non-Russian			
457		Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
458	Civil Works	0	15,314	17,767	0	33,081	0	0	0	33,081
459	Combustion Turbine	0	0	992	0	992	192,456	0	192,456	193,448
460	HRSG	0	0	3,967	0	3,967	55,331	0	55,331	59,298
461	Steam Turbines	0	0	372	0	372	43,303	0	43,303	43,674
462	Distributed Control System	0	0	0	0	0	4,651	0	4,651	4,651
463	Mechanical Package	34,296	18,873	11,578	0	64,747	41,699	0	41,699	106,446
464	Electrical Package	25,066	12,708	10,634	0	48,408	0	0	0	48,408
465	Switchyard	5,360	2,653	14,009	0	22,021	47,822	0	47,822	69,843
466	Engineering & Project Mgmt.	0	0	0	64,152	64,152	0	86,365	86,365	150,517
467	Subtotal Generation Plant	64,721	49,548	59,319	64,152	237,740	385,262	86,365	471,626	709,366
468	Transmission Line	0	0	0	0	0	0	0	0	0
469	Gas Pipeline	0	0	0	0	0	0	0	0	0
470	Total Project Costs, w VAT	64,721	49,548	59,319	64,152	237,740	385,262	86,365	471,626	**709,366**

DEBT SERVICE CASH FLOWS
Total Amount of World Bank Loan

Total Loan Amount ($000)	$500,000
Issue Date	12/1/96
First Drawdown Amount	$31,797
First Drawdown Date	12/1/96
Second Drawdown Amount	$101,271
Second Drawdown Date	12/1/97
Third Drawdown Amount	$163,668
Third Drawdown Date	12/1/98
Fourth Drawdown Amount	$126,094
Fourth Drawdown Date	12/1/99
Fifth Drawdown Amount	$0
Fifth Drawdown Date	12/1/00
Capitalized Interest	$77,171
First Interest Payment	12/1/01
First Principal Payment	12/1/01
Last Principal Payment	12/1/13
Fixed Interest Rate (%/year)	8.0%

Year	Year Ending	Applied to Principal	Interest Rate	Interest Accrued	Interest Paid	Capitalized Interest	Debt Service	Principal Outstanding	Loan Drawdown	Principal Borrowed
0	12/31/95	0	na	0	0	0	0	0		0
1	12/31/96	0	8.00%	202	0	202	0	31,999	31,797	31,797
2	12/31/97	0	8.00%	3,204	0	3,204	0	136,473	101,271	133,068
3	12/31/98	0	8.00%	11,958	0	11,958	0	312,099	163,668	296,735
4	12/31/99	0	8.00%	25,701	0	25,701	0	463,894	126,094	422,829
5	12/31/00	0	8.00%	36,106	0	36,106	0	500,000	0	422,829
6	12/31/01	38,462	8.00%	40,000	40,000	0	78,462	461,538	0	422,829
7	12/31/02	38,462	8.00%	36,923	36,923	0	75,385	423,077	0	422,829
8	12/31/03	38,462	8.00%	33,846	33,846	0	72,308	384,615	0	422,829
9	12/31/04	38,462	8.00%	30,769	30,769	0	69,231	346,154	0	422,829
10	12/31/05	38,462	8.00%	27,692	27,692	0	66,154	307,692	0	422,829
11	12/31/06	38,462	8.00%	24,615	24,615	0	63,077	269,231	0	422,829
12	12/31/07	38,462	8.00%	21,538	21,538	0	60,000	230,769	0	422,829
13	12/31/08	38,462	8.00%	18,462	18,462	0	56,923	192,308	0	422,829
14	12/31/09	38,462	8.00%	15,385	15,385	0	53,846	153,846	0	422,829
15	12/31/10	38,462	8.00%	12,308	12,308	0	50,769	115,385	0	422,829
16	12/31/11	38,462	8.00%	9,231	9,231	0	47,692	76,923	0	422,829
17	12/31/12	38,462	8.00%	6,154	6,154	0	44,615	38,462	0	422,829
18	12/31/13	38,462	8.00%	3,077	3,077	0	41,538	0	0	422,829

DEBT SERVICE CASH FLOWS
World Bank Drawdown #1 (12/1/96)

Drawdown Amount ($000)	31,797
Capitalized Interest	11,500
Issue Date	12/1/96
First Interest Payment	12/1/01
First Principal Payment	12/1/01
Last Principal Payment	12/1/13
Fixed Interest Rate (%/year)	8.00%

Year	Year Ending	Applied to Principal	Interest Rate	Interest Accrued	Interest Paid	Capitalized Interest	Debt Service	Principal at Payment	Principal at Year End	Loan Drawdown	Principal Borrowed
0	12/31/95	0	na	0	0		0	0	0		0
1	12/31/96	0	8.00%	202	0	202	0	31,797	31,999	31,797	31,797
2	12/31/97	0	8.00%	2,560	0	2,560	0	34,341	34,559	0	31,797
3	12/31/98	0	8.00%	2,765	0	2,765	0	37,088	37,324	0	31,797
4	12/31/99	0	8.00%	2,969	0	2,969	0	37,324	40,292	0	31,797
5	12/31/00	0	8.00%	3,005	0	3,005	0	40,292	43,297	0	31,797
6	12/31/01	3,331	8.00%	3,464	3,464	0	6,794	43,297	39,966	0	31,797
7	12/31/02	3,331	8.00%	3,197	3,197	0	6,528	39,966	36,636	0	31,797
8	12/31/03	3,331	8.00%	2,931	2,931	0	6,261	36,636	33,305	0	31,797
9	12/31/04	3,331	8.00%	2,664	2,664	0	5,995	33,305	29,975	0	31,797
10	12/31/05	3,331	8.00%	2,398	2,398	0	5,729	29,975	26,644	0	31,797
11	12/31/06	3,331	8.00%	2,132	2,132	0	5,462	26,644	23,314	0	31,797
12	12/31/07	3,331	8.00%	1,865	1,865	0	5,196	23,314	19,983	0	31,797
13	12/31/08	3,331	8.00%	1,599	1,599	0	4,929	19,983	16,653	0	31,797
14	12/31/09	3,331	8.00%	1,332	1,332	0	4,663	16,653	13,322	0	31,797
15	12/31/10	3,331	8.00%	1,066	1,066	0	4,396	13,322	9,992	0	31,797
16	12/31/11	3,331	8.00%	799	799	0	4,130	9,992	6,661	0	31,797
17	12/31/12	3,331	8.00%	533	533	0	3,863	6,661	3,331	0	31,797
18	12/31/13	3,331	8.00%	266	266	0	3,597	3,331	0	0	31,797
19	12/31/14	0	8.00%	0	0	0	0	0	0	0	31,797
20	12/31/15	0	8.00%	0	0	0	0	0	0	0	31,797
21	12/31/16	0	8.00%	0	0	0	0	0	0	0	31,797
22	12/31/17	0	8.00%	0	0	0	0	0	0	0	31,797
23	12/31/18	0	8.00%	0	0	0	0	0	0	0	31,797
24	12/31/19	0	8.00%	0	0	0	0	0	0	0	31,797
25	12/31/20	0	8.00%	0	0	0	0	0	0	0	31,797
26	12/31/21	0	8.00%	0	0	0	0	0	0	0	31,797
27	12/31/22	0	8.00%	0	0	0	0	0	0	0	31,797
28	12/31/23	0	8.00%	0	0	0	0	0	0	0	31,797
29	12/31/24	0	8.00%	0	0	0	0	0	0	0	31,797
30	12/31/25	0	8.00%	0	0	0	0	0	0	0	31,797
31	12/31/26	0	8.00%	0	0	0	0	0	0	0	31,797

DEBT SERVICE CASH FLOWS
World Bank Drawdown #2 (12/1/97)

Drawdown Amount ($000)	101,271
Capitalized Interest	26,412
Issue Date	12/1/97
First Interest Payment	12/1/01
First Principal Payment	12/1/01
Last Principal Payment	12/1/13
Fixed Interest Rate (%/year)	8.00%

Year	Year Ending	Applied to Principal	Interest Rate	Interest Accrued	Interest Paid	Capitalized Interest	Debt Service	Principal at Payment	Principal at Year End	Loan Drawdown	Principal Borrowed
0	12/31/95	0	na	0	0	0	0	0	0	0	0
1	12/31/96	0	8.00%	0	0	0	0	0	0	0	0
2	12/31/97	0	8.00%	644	0	644	0	101,271	101,914	101,271	101,271
3	12/31/98	0	8.00%	8,153	0	8,153	0	109,372	110,068	0	101,271
4	12/31/99	0	8.00%	8,754	0	8,754	0	110,068	118,822	0	101,271
5	12/31/00	0	8.00%	8,861	0	8,861	0	118,822	127,683	0	101,271
6	12/31/01	9,822	8.00%	10,215	10,215	0	20,036	127,683	117,861	0	101,271
7	12/31/02	9,822	8.00%	9,429	9,429	0	19,251	117,861	108,039	0	101,271
8	12/31/03	9,822	8.00%	8,643	8,643	0	18,465	108,039	98,218	0	101,271
9	12/31/04	9,822	8.00%	7,857	7,857	0	17,679	98,218	88,396	0	101,271
10	12/31/05	9,822	8.00%	7,072	7,072	0	16,893	88,396	78,574	0	101,271
11	12/31/06	9,822	8.00%	6,286	6,286	0	16,108	78,574	68,752	0	101,271
12	12/31/07	9,822	8.00%	5,500	5,500	0	15,322	68,752	58,931	0	101,271
13	12/31/08	9,822	8.00%	4,714	4,714	0	14,536	58,931	49,109	0	101,271
14	12/31/09	9,822	8.00%	3,929	3,929	0	13,750	49,109	39,287	0	101,271
15	12/31/10	9,822	8.00%	3,143	3,143	0	12,965	39,287	29,465	0	101,271
16	12/31/11	9,822	8.00%	2,357	2,357	0	12,179	29,465	19,644	0	101,271
17	12/31/12	9,822	8.00%	1,571	1,571	0	11,393	19,644	9,822	0	101,271
18	12/31/13	9,822	8.00%	786	786	0	10,607	9,822	0	0	101,271
19	12/31/14	0	8.00%	0	0	0	0	0	0	0	101,271
20	12/31/15	0	8.00%	0	0	0	0	0	0	0	101,271
21	12/31/16	0	8.00%	0	0	0	0	0	0	0	101,271
22	12/31/17	0	8.00%	0	0	0	0	0	0	0	101,271
23	12/31/18	0	8.00%	0	0	0	0	0	0	0	101,271
24	12/31/19	0	8.00%	0	0	0	0	0	0	0	101,271
25	12/31/20	0	8.00%	0	0	0	0	0	0	0	101,271
26	12/31/21	0	8.00%	0	0	0	0	0	0	0	101,271
27	12/31/22	0	8.00%	0	0	0	0	0	0	0	101,271
28	12/31/23	0	8.00%	0	0	0	0	0	0	0	101,271
29	12/31/24	0	8.00%	0	0	0	0	0	0	0	101,271
30	12/31/25	0	8.00%	0	0	0	0	0	0	0	101,271
31	12/31/26	0	8.00%	0	0	0	0	0	0	0	101,271

DEBT SERVICE CASH FLOWS
World Bank Drawdown #3 (12/1/98)

Drawdown Amount ($000)	163,668
Capitalized Interest	28,365
Issue Date	12/1/98
First Interest Payment	12/1/01
First Principal Payment	12/1/01
Last Principal Payment	12/1/13
Fixed Interest Rate (%/year)	8.00%

Year	Year Ending	Applied to Principal	Interest Rate	Interest Accrued	Interest Paid	Capitalized Interest	Debt Service	Principal at Payment	Principal at Year End	Loan Drawdown	Principal Borrowed
0	12/31/95	0	na	0	0	0	0	0	0	0	0
1	12/31/96	0	8.00%	0	0	0	0	0	0	0	0
2	12/31/97	0	8.00%	0	0	0	0	0	0	0	0
3	12/31/98	0	8.00%	1,040	0	1,040	0	163,668	164,708	163,668	163,668
4	12/31/99	0	8.00%	13,177	0	13,177	0	176,761	177,885	0	163,668
5	12/31/00	0	8.00%	14,148	0	14,148	0	177,885	192,033	0	163,668
6	12/31/01	14,772	8.00%	15,363	15,363	0	30,134	192,033	177,261	0	163,668
7	12/31/02	14,772	8.00%	14,181	14,181	0	28,953	177,261	162,489	0	163,668
8	12/31/03	14,772	8.00%	12,999	12,999	0	27,771	162,489	147,717	0	163,668
9	12/31/04	14,772	8.00%	11,817	11,817	0	26,589	147,717	132,946	0	163,668
10	12/31/05	14,772	8.00%	10,636	10,636	0	25,407	132,946	118,174	0	163,668
11	12/31/06	14,772	8.00%	9,454	9,454	0	24,226	118,174	103,402	0	163,668
12	12/31/07	14,772	8.00%	8,272	8,272	0	23,044	103,402	88,630	0	163,668
13	12/31/08	14,772	8.00%	7,090	7,090	0	21,862	88,630	73,859	0	163,668
14	12/31/09	14,772	8.00%	5,909	5,909	0	20,680	73,859	59,087	0	163,668
15	12/31/10	14,772	8.00%	4,727	4,727	0	19,499	59,087	44,315	0	163,668
16	12/31/11	14,772	8.00%	3,545	3,545	0	18,317	44,315	29,543	0	163,668
17	12/31/12	14,772	8.00%	2,363	2,363	0	17,135	29,543	14,772	0	163,668
18	12/31/13	14,772	8.00%	1,182	1,182	0	15,953	14,772	0	0	163,668
19	12/31/14	0	8.00%	0	0	0	0	0	0	0	163,668
20	12/31/15	0	8.00%	0	0	0	0	0	0	0	163,668
21	12/31/16	0	8.00%	0	0	0	0	0	0	0	163,668
22	12/31/17	0	8.00%	0	0	0	0	0	0	0	163,668
23	12/31/18	0	8.00%	0	0	0	0	0	0	0	163,668
24	12/31/19	0	8.00%	0	0	0	0	0	0	0	163,668
25	12/31/20	0	8.00%	0	0	0	0	0	0	0	163,668
26	12/31/21	0	8.00%	0	0	0	0	0	0	0	163,668
27	12/31/22	0	8.00%	0	0	0	0	0	0	0	163,668
28	12/31/23	0	8.00%	0	0	0	0	0	0	0	163,668
29	12/31/24	0	8.00%	0	0	0	0	0	0	0	163,668
30	12/31/25	0	8.00%	0	0	0	0	0	0	0	163,668
31	12/31/26	0	8.00%	0	0	0	0	0	0	0	163,668

DEBT SERVICE CASH FLOWS
World Bank Drawdown #4 (12/1/99)

Drawdown Amount ($000)	126,094
Capitalized Interest	10,894
Issue Date	12/1/99
First Interest Payment	12/1/01
First Principal Payment	12/1/01
Last Principal Payment	12/1/13
Fixed Interest Rate (%/year)	8.00%

Year	Year Ending	Applied to Principal	Interest Rate	Interest Accrued	Interest Paid	Capitalized Interest	Debt Service	Principal at Payment	Principal at Year End	Loan Drawdown	Principal Borrowed
0	12/31/95	0	na	0	0	0	0	0	0		0
1	12/31/96	0	8.00%	0	0	0	0	0	0	0	0
2	12/31/97	0	8.00%	0	0	0	0	0	0	0	0
3	12/31/98	0	8.00%	0	0	0	0	0	0	0	0
4	12/31/99	0	8.00%	801	0	801	0	126,094	126,895	126,094	126,094
5	12/31/00	0	8.00%	10,093	0	10,093	0	126,895	136,988	0	126,094
6	12/31/01	10,538	8.00%	10,959	10,959	0	21,497	136,988	126,450	0	126,094
7	12/31/02	10,538	8.00%	10,116	10,116	0	20,654	126,450	115,913	0	126,094
8	12/31/03	10,538	8.00%	9,273	9,273	0	19,811	115,913	105,375	0	126,094
9	12/31/04	10,538	8.00%	8,430	8,430	0	18,968	105,375	94,838	0	126,094
10	12/31/05	10,538	8.00%	7,587	7,587	0	18,125	94,838	84,300	0	126,094
11	12/31/06	10,538	8.00%	6,744	6,744	0	17,282	84,300	73,763	0	126,094
12	12/31/07	10,538	8.00%	5,901	5,901	0	16,439	73,763	63,225	0	126,094
13	12/31/08	10,538	8.00%	5,058	5,058	0	15,596	63,225	52,688	0	126,094
14	12/31/09	10,538	8.00%	4,215	4,215	0	14,753	52,688	42,150	0	126,094
15	12/31/10	10,538	8.00%	3,372	3,372	0	13,910	42,150	31,613	0	126,094
16	12/31/11	10,538	8.00%	2,529	2,529	0	13,067	31,613	21,075	0	126,094
17	12/31/12	10,538	8.00%	1,686	1,686	0	12,224	21,075	10,538	0	126,094
18	12/31/13	10,538	8.00%	843	843	0	11,381	10,538	0	0	126,094
19	12/31/14	0	8.00%	0	0	0	0	0	0	0	126,094
20	12/31/15	0	8.00%	0	0	0	0	0	0	0	126,094
21	12/31/16	0	8.00%	0	0	0	0	0	0	0	126,094
22	12/31/17	0	8.00%	0	0	0	0	0	0	0	126,094
23	12/31/18	0	8.00%	0	0	0	0	0	0	0	126,094
24	12/31/19	0	8.00%	0	0	0	0	0	0	0	126,094
25	12/31/20	0	8.00%	0	0	0	0	0	0	0	126,094
26	12/31/21	0	8.00%	0	0	0	0	0	0	0	126,094
27	12/31/22	0	8.00%	0	0	0	0	0	0	0	126,094
28	12/31/23	0	8.00%	0	0	0	0	0	0	0	126,094
29	12/31/24	0	8.00%	0	0	0	0	0	0	0	126,094
30	12/31/25	0	8.00%	0	0	0	0	0	0	0	126,094
31	12/31/26	0	8.00%	0	0	0	0	0	0	0	126,094

WORKING CAPITAL	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Project Year	0	1	2	3	4	5	6	7	8	9	10	11	12
1 **Working Capital**													
2 Cash and cash equivalents (days sales)	3	0	0	211	10	3	70	66	62	59	55	52	48
3 Accounts Receivables (days sales)	45	0	0	1,080	85	45	45	45	45	45	45	45	45
4 Uncollectible Threshold (days sales)	45	0	0	1,080	85	45	45	45	45	45	45	45	45
5 Inventories (days sales)	18	0	0	1,151	55	19	16	16	16	16	16	16	16
6 Advances (days sales)	11	0	0	284	14	11	11	11	11	11	11	11	11
7 Other Current Assets (days sales)	2	0	0	48	3	2	2	2	2	2	2	2	2
8 Accounts Payables (days sales)	30	0	0	720	38	30	30	30	30	30	30	30	30
9 Other Current Liabilities (days sales)	5	0	0	120	6	5	5	5	5	5	5	5	5
10													
11 Sales, Gross (less Gvt. Subsidy)		0	0	2,752	59,179	178,563	212,548	217,437	221,785	226,443	231,198	236,053	241,010
12													
13 Cash Requirements (6 month debt service, 3 days sales)		0	0	1,587	1,625	1,661	40,978	39,479	37,977	36,477	34,977	33,479	31,981
14 Inventory Requirement:													
15 - Fuel ($2.2 million reserves, inflation adjusted)	2,200	2,244	2,280	2,328	2,384	2,436	2,497	2,554	2,606	2,660	2,716	2,773	2,831
16 - Spare Parts ($6 million, inflation adjusted)	6,000	6,120	6,218	6,348	6,501	6,644	6,810	6,967	7,106	7,255	7,408	7,563	7,722
17 Total Inventory Requirements	0	0	0	8,676	8,885	9,080	9,307	9,521	9,711	9,915	10,124	10,336	10,553
18													
19 Months of GT Operation		0	0	1	18	5	0	0	0	0	0	0	0
20 Months of CC Operation		0	0	0	1	19	24	24	24	24	24	24	24
21 Average Months of System Operation		0	0	1	10	12	12	12	12	12	12	12	12
22 Approximate Days of Operation		0	0	15	289	365	365	365	365	365	365	365	365
23 Multiplier of 365				24.00	1.26	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
24													
25 Accounts Receivable, Gross		0	0	8,143	13,824	22,015	26,205	26,807	27,343	27,918	28,504	29,102	29,714
26 Uncollectibles Threshold		0	0	8,143	13,824	22,015	26,205	26,807	27,343	27,918	28,504	29,102	29,714
27 Bad Debt Expense via Threshold		0	0	0	0	0	0	0	0	0	0	0	0
28 Bad Debt Expense as % Revenue		0	0	275	2,959	3,571	4,251	4,349	4,436	4,529	4,624	4,721	4,820
29 Total Bad Debt Expense		0	0	275	2,959	3,571	4,251	4,349	4,436	4,529	4,624	4,721	4,820
30 Accounts Receivable, Net		0	0	7,868	10,865	18,443	21,954	22,459	22,908	23,389	23,880	24,381	24,893
31													
32 **Current Assets**													
33 Cash and Temporary Cash Investments		0	0	1,587	1,625	1,661	40,978	39,479	37,977	36,477	34,977	33,479	31,981
34 Accounts Receivable, Net		0	0	7,868	10,865	18,443	21,954	22,459	22,908	23,389	23,880	24,381	24,893
35 Inventories		0	0	8,676	8,885	9,080	9,307	9,521	9,711	9,915	10,124	10,336	10,553
36 Advances		0	0	1,990	2,253	5,381	6,406	6,553	6,684	6,824	6,968	7,114	7,263
37 Other		0	0	382	410	978	1,165	1,191	1,215	1,241	1,267	1,293	1,321
38 *Total Current Assets*		0	0	20,484	24,037	35,544	79,809	79,203	78,495	77,846	77,215	76,604	76,012
39													
40 **Current Liabilities**													
41 Accounts payable		0	0	5,429	6,144	14,676	17,470	17,872	18,229	18,612	19,003	19,402	19,809
42 Short-Term Loans and Other Liabilities		0	0	905	1,024	2,446	2,912	2,979	3,038	3,102	3,167	3,234	3,302
43 Total Current Liabilities		0	0	6,333	7,168	17,123	20,381	20,850	21,267	21,714	22,170	22,635	23,111
44													
45 **Working Capital**		0	0	14,150	16,869	18,422	59,427	58,353	57,228	56,132	55,045	53,968	52,901
46													
47 **Changes in Working Capital**				14,150	2,719	1,552	41,006	-1,074	-1,125	-1,096	-1,087	-1,077	-1,067

WORKING CAPITAL	2008 13	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27
1 **Working Capital**															
2 Cash and cash equivalents (days sales)	45	42	40	37	35	33	3	3	3	3	3	3	3	3	3
3 Accounts Receivables (days sales)	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
4 Uncollectible Threshold (days sales)	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
5 Inventories (days sales)	16	16	16	16	17	17	17	18	18	18	18	19	19	19	20
6 Advances (days sales)	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
7 Other Current Assets (days sales)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
8 Accounts Payables (days sales)	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
9 Other Current Liabilities (days sales)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
10															
11 Sales, Gross (less Gvt. Subsidy)	246,072	251,239	252,667	254,045	255,369	256,636	257,844	258,990	260,070	261,081	262,020	262,884	263,668	264,369	264,983
12															
13 Cash Requirements (6 month debt service	30,484	28,988	27,461	25,934	24,407	22,879	2,119	2,129	2,138	2,146	2,154	2,161	2,167	2,173	2,178
14 Inventory Requirement:															
15 - Fuel ($2.2 million reserves, inflation ac	2,891	2,952	3,014	3,077	3,141	3,207	3,275	3,344	3,414	3,485	3,559	3,633	3,710	3,788	3,867
16 - Spare Parts ($6 million, inflation adjus	7,884	8,050	8,219	8,391	8,567	8,747	8,931	9,119	9,310	9,506	9,705	9,909	10,117	10,330	10,547
17 Total Inventory Requirements	10,775	11,001	11,232	11,468	11,709	11,955	12,206	12,462	12,724	12,991	13,264	13,542	13,827	14,117	14,414
18															
19 Months of GT Operation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20 Months of CC Operation	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
21 Average Months of System Operation	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
22 Approximate Days of Operation	365	365	365	365	365	365	365	365	365	365	365	365	365	365	365
23 Multiplier of 365	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
24															
25 Accounts Receivable, Gross	30,338	30,975	31,151	31,321	31,484	31,640	31,789	31,930	32,063	32,188	32,304	32,410	32,507	32,593	32,669
26 Uncollectibles Threshold	30,338	30,975	31,151	31,321	31,484	31,640	31,789	31,930	32,063	32,188	32,304	32,410	32,507	32,593	32,669
27 Bad Debt Expense via Threshold	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28 Bad Debt Expense as % Revenue	4,921	5,025	5,053	5,081	5,107	5,133	5,157	5,180	5,201	5,222	5,240	5,258	5,273	5,287	5,300
29 Total Bad Debt Expense	4,921	5,025	5,053	5,081	5,107	5,133	5,157	5,180	5,201	5,222	5,240	5,258	5,273	5,287	5,300
30 Accounts Receivable, Net	25,416	25,950	26,097	26,240	26,376	26,507	26,632	26,750	26,862	26,966	27,063	27,153	27,234	27,306	27,369
31															
32 **Current Assets**															
33 Cash and Temporary Cash Investments	30,484	28,988	27,461	25,934	24,407	22,879	2,119	2,129	2,138	2,146	2,154	2,161	2,167	2,173	2,178
34 Accounts Receivable, Net	25,416	25,950	26,097	26,240	26,376	26,507	26,632	26,750	26,862	26,966	27,063	27,153	27,234	27,306	27,369
35 Inventories	10,775	11,001	11,232	11,468	11,709	11,955	12,206	12,462	12,724	12,991	13,264	13,542	13,827	14,117	14,414
36 Advances	7,416	7,572	7,615	7,656	7,696	7,734	7,771	7,805	7,838	7,868	7,897	7,923	7,946	7,967	7,986
37 Other	1,348	1,377	1,384	1,392	1,399	1,406	1,413	1,419	1,425	1,431	1,436	1,440	1,445	1,449	1,452
38 Total Current Assets	75,439	74,887	73,790	72,690	71,587	70,481	50,141	50,566	50,986	51,402	51,813	52,219	52,618	53,012	53,399
39															
40 **Current Liabilities**															
41 Accounts payable	20,225	20,650	20,767	20,880	20,989	21,093	21,193	21,287	21,376	21,459	21,536	21,607	21,671	21,729	21,779
42 Short-Term Loans and Other Liabilities	3,371	3,442	3,461	3,480	3,498	3,516	3,532	3,548	3,563	3,576	3,589	3,601	3,612	3,621	3,630
43 Total Current Liabilities	23,596	24,091	24,228	24,360	24,487	24,609	24,725	24,835	24,938	25,035	25,125	25,208	25,283	25,350	25,409
44															
45 **Working Capital**	51,843	50,796	49,562	48,330	47,100	45,872	25,416	25,731	26,048	26,367	26,688	27,011	27,335	27,662	27,989
46															
47 **Changes in Working Capital**	-1,058	-1,047	-1,234	-1,232	-1,230	-1,228	-20,456	315	317	319	321	323	325	326	328

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WORKING CAPITAL	2023 28	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39
1 **Working Capital**												
2 Cash and cash equivalents (days sales)	3	3	3	3	3	3	3	3	3	3	3	3
3 Accounts Receivables (days sales)	45	45	45	45	45	45	45	45	45	45	45	45
4 Uncollectible Threshold (days sales)	45	45	45	45	45	45	45	45	45	45	45	45
5 Inventories (days sales)	20	21	21	21	22	22	23	20	16	13	10	7
6 Advances (days sales)	11	11	11	11	11	11	11	11	11	11	11	11
7 Other Current Assets (days sales)	2	2	2	2	2	2	2	2	2	2	2	2
8 Accounts Payables (days sales)	30	30	30	30	30	30	30	30	30	30	30	30
9 Other Current Liabilities (days sales)	5	5	5	5	5	5	5	5	5	5	5	5
10												
11 Sales, Gross (less Gvt. Subsidy)	265,506	265,935	266,264	266,490	266,608	266,614	266,502	266,268	265,906	265,412	264,780	264,004
12												
13 Cash Requirements (6 month debt service	2,182	2,186	2,188	2,190	2,191	2,191	2,190	2,189	2,186	2,181	2,176	2,170
14 Inventory Requirement:												
15 - Fuel ($2.2 million reserves, inflation ac	3,948	4,031	4,116	4,202	4,291	4,381	4,473	4,567	4,662	4,760	4,860	4,962
16 - Spare Parts ($8 million, inflation adjus	10,768	10,994	11,225	11,461	11,701	11,947	12,198	9,758	7,319	4,879	2,440	0
17 Total Inventory Requirements	14,716	15,025	15,341	15,663	15,992	16,328	16,671	14,325	11,981	9,640	7,300	4,962
18												
19 Months of GT Operation	0	0	0	0	0	0	0	0	0	0	0	0
20 Months of CC Operation	24	24	24	24	24	24	24	24	24	24	24	24
21 Average Months of System Operation	12	12	12	12	12	12	12	12	12	12	12	12
22 Approximate Days of Operation	365	365	365	365	365	365	365	365	365	365	365	365
23 Multiplier of 365	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
24												
25 Accounts Receivable, Gross	32,734	32,786	32,827	32,855	32,870	32,870	32,856	32,828	32,783	32,722	32,644	32,548
26 Uncollectibles Threshold	32,734	32,786	32,827	32,855	32,870	32,870	32,856	32,828	32,783	32,722	32,644	32,548
27 Bad Debt Expense via Threshold	0	0	0	0	0	0	0	0	0	0	0	0
28 Bad Debt Expense as % Revenue	5,310	5,319	5,325	5,330	5,332	5,332	5,330	5,325	5,318	5,308	5,296	5,280
29 Total Bad Debt Expense	5,310	5,319	5,325	5,330	5,332	5,332	5,330	5,325	5,318	5,308	5,296	5,280
30 Accounts Receivable, Net	27,424	27,468	27,502	27,525	27,537	27,538	27,526	27,502	27,465	27,414	27,349	27,268
31												
32 **Current Assets**												
33 Cash and Temporary Cash Investments	2,182	2,186	2,188	2,190	2,191	2,191	2,190	2,189	2,186	2,181	2,176	2,170
34 Accounts Receivable, Net	27,424	27,468	27,502	27,525	27,537	27,538	27,526	27,502	27,465	27,414	27,349	27,268
35 Inventories	14,716	15,025	15,341	15,663	15,992	16,328	16,671	14,325	11,981	9,640	7,300	4,962
36 Advances	8,002	8,014	8,024	8,031	8,035	8,035	8,032	8,025	8,014	7,999	7,980	7,956
37 Other	1,455	1,457	1,459	1,460	1,461	1,461	1,460	1,459	1,457	1,454	1,451	1,447
38 Total Current Assets	53,778	54,151	54,515	54,870	55,216	55,553	55,879	53,499	51,102	48,688	46,255	43,804
39												
40 **Current Liabilities**												
41 Accounts payable	21,822	21,858	21,885	21,903	21,913	21,913	21,904	21,885	21,855	21,815	21,763	21,699
42 Short-Term Loans and Other Liabilities	3,637	3,643	3,647	3,651	3,652	3,652	3,651	3,648	3,643	3,636	3,627	3,616
43 Total Current Liabilities	25,460	25,501	25,532	25,554	25,565	25,566	25,555	25,533	25,498	25,450	25,390	25,315
44												
45 **Working Capital**	28,319	28,650	28,982	29,316	29,651	29,987	30,324	27,967	25,604	23,237	20,865	18,488
46												
47 **Changes in Working Capital**	330	331	332	334	335	336	337	-2,358	-2,362	-2,367	-2,372	-2,377

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	DEPRECIATION / CAPITAL EXPENDITURES	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Project Year	0	1	2	3	4	[illegible]	[illegible]	7	8	[illegible]	10	11	12	13	14	[illegible]	16	[illegible]
1	Capital Expenditures (000 US$ 1995)																		
2	Generation Plant (real & infl'n escalated)	37,587	159,628	243,289	219,058	95,637	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
4	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
6	Transmission Line (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
8	Gas Pipeline (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
10	Capital Repairs	0	0	0	0	0	1,565	3,278	5,113	7,106	9,260	9,653	10,062	10,489	10,934	11,398	11,882	12,387	12,912
11	Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
12	Office Equipment	0	1,889	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Years to Depreciate	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
14	Total Capital Expenditures	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
15																			
16	New Capital Investment																		

17	1996		1996			
18	Generation Plant (real & infl'n escalated)	25	37,587			
19	Second Stage Total (real & inflation adj)	25	0			
20	Transmission Line (real & infl'n escalated)	25	0			
21	Gas Pipeline (real & infl'n escalated)	25	0			
22	Capital Repairs	25	0			
23	Office Equipment	7	0			
24	1997			1997		
25	Generation Plant (real & infl'n escalated)	25		159,628		
26	Second Stage Total (real & inflation adj)	25		0		
27	Transmission Line (real & infl'n escalated)	25		0		
28	Gas Pipeline (real & infl'n escalated)	25		0		
29	Capital Repairs	25		0		
30	Office Equipment	7		1,889		
31	1998				1998	
32	Generation Plant (real & infl'n escalated)	25			243,289	
33	Second Stage Total (real & inflation adj)	25			0	
34	Transmission Line (real & infl'n escalated)	25			0	
35	Gas Pipeline (real & infl'n escalated)	25			0	
36	Capital Repairs	25			0	
37	Office Equipment	7			0	
38	1999					1999
39	Generation Plant (real & infl'n escalated)	25				219,058
40	Second Stage Total (real & inflation adj)	25				0
41	Transmission Line (real & infl'n escalated)	25				0
42	Gas Pipeline (real & infl'n escalated)	25				0
43	Capital Repairs	25				0
44	Office Equipment	7				0

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KUBAN GRES -- 6. Depreciation Capital Expenditures

DRAFT -- FOR DISCUSSION PURPOSES

DEPRECIATION & CAPITAL EXPENDITURES	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1 Capital Expenditures (000 US$ 1995)																					
2 Generation Plant (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
4 Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
6 Transmission Line (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
8 Gas Pipeline (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
10 Capital Repairs	13,460	14,032	14,627	15,248	15,895	16,570	17,273	18,006	18,770	19,567	20,397	21,263	22,165	23,108	24,086	25,109	26,174	27,285	28,443	29,650	30,909
11 Years to Depreciate	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
12 Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 Years to Depreciate	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
14 Total Capital Expenditures	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
15																					
16 New Capital Investment																					
17 1996																					
18 Generation Plant (real & infl'n escalated)																					
19 Second Stage Total (real & inflation adj)																					
20 Transmission Line (real & infl'n escalated)																					
21 Gas Pipeline (real & infl'n escalated)																					
22 Capital Repairs																					
23 Office Equipment																					
24 1997																					
25 Generation Plant (real & infl'n escalated)																					
26 Second Stage Total (real & inflation adj)																					
27 Transmission Line (real & infl'n escalated)																					
28 Gas Pipeline (real & infl'n escalated)																					
29 Capital Repairs																					
30 Office Equipment																					
31 1998																					
32 Generation Plant (real & infl'n escalated)																					
33 Second Stage Total (real & inflation adj)																					
34 Transmission Line (real & infl'n escalated)																					
35 Gas Pipeline (real & infl'n escalated)																					
36 Capital Repairs																					
37 Office Equipment																					
38 1999																					
39 Generation Plant (real & infl'n escalated)																					
40 Second Stage Total (real & inflation adj)																					
41 Transmission Line (real & infl'n escalated)																					
42 Gas Pipeline (real & infl'n escalated)																					
43 Capital Repairs																					
44 Office Equipment																					

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DEPRECIATION & CAPITAL EXPENDITURES [illegible] Project Year [illegible]

45	2000		2000						
46	Generation Plant (real & infl'n escalated)	25	95,637						
47	Second Stage Total (real & inflation adj)	25	0						
48	Transmission Line (real & infl'n escalated)	25	0						
49	Gas Pipeline (real & infl'n escalated)	25	0						
50	Capital Repairs	25	0						
51	Office Equipment	7	0						
52	2001			2001					
53	Generation Plant (real & infl'n escalated)	25		0					
54	Second Stage Total (real & inflation adj)	25		0					
55	Transmission Line (real & infl'n escalated)	25		0					
56	Gas Pipeline (real & infl'n escalated)	25		0					
57	Capital Repairs	25		1,565					
58	Office Equipment	7		0					
59	2002				2002				
60	Generation Plant (real & infl'n escalated)	25			0				
61	Second Stage Total (real & inflation adj)	25			0				
62	Transmission Line (real & infl'n escalated)	25			0				
63	Gas Pipeline (real & infl'n escalated)	25			0				
64	Capital Repairs	25			3,276				
65	Office Equipment	7			0				
66	2003					2003			
67	Generation Plant (real & infl'n escalated)	25				0			
68	Second Stage Total (real & inflation adj)	25				0			
69	Transmission Line (real & infl'n escalated)	25				0			
70	Gas Pipeline (real & infl'n escalated)	25				0			
71	Capital Repairs	25				5,113			
72	Office Equipment	7				0			
73	2004						2004		
74	Generation Plant (real & infl'n escalated)	25					0		
75	Second Stage Total (real & inflation adj)	25					0		
76	Transmission Line (real & infl'n escalated)	25					0		
77	Gas Pipeline (real & infl'n escalated)	25					0		
78	Capital Repairs	25					7,106		
79	Office Equipment	7					0		
80	2005							2005	
81	Generation Plant (real & infl'n escalated)	25						0	
82	Second Stage Total (real & inflation adj)	25						0	
83	Transmission Line (real & infl'n escalated)	25						0	
84	Gas Pipeline (real & infl'n escalated)	25						0	
85	Capital Repairs	25						9,260	
86	Office Equipment	7						0	
87	2006								2006
88	Generation Plant (real & infl'n escalated)	25							0
89	Second Stage Total (real & inflation adj)	25							0
90	Transmission Line (real & infl'n escalated)	25							0
91	Gas Pipeline (real & infl'n escalated)	25							0
92	Capital Repairs	25							9,653
93	Office Equipment	7							0

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[illegible]

45	2000
46	Generation Plant (real & infl'n escalated)
47	Second Stage Total (real & inflation adj)
48	Transmission Line (real & infl'n escalated)
49	Gas Pipeline (real & infl'n escalated)
50	Capital Repairs
51	Office Equipment
52	2001
53	Generation Plant (real & infl'n escalated)
54	Second Stage Total (real & inflation adj)
55	Transmission Line (real & infl'n escalated)
56	Gas Pipeline (real & infl'n escalated)
57	Capital Repairs
58	Office Equipment
59	2002
60	Generation Plant (real & infl'n escalated)
61	Second Stage Total (real & inflation adj)
62	Transmission Line (real & infl'n escalated)
63	Gas Pipeline (real & infl'n escalated)
64	Capital Repairs
65	Office Equipment
66	2003
67	Generation Plant (real & infl'n escalated)
68	Second Stage Total (real & inflation adj)
69	Transmission Line (real & infl'n escalated)
70	Gas Pipeline (real & infl'n escalated)
71	Capital Repairs
72	Office Equipment
73	2004
74	Generation Plant (real & infl'n escalated)
75	Second Stage Total (real & inflation adj)
76	Transmission Line (real & infl'n escalated)
77	Gas Pipeline (real & infl'n escalated)
78	Capital Repairs
79	Office Equipment
80	2005
81	Generation Plant (real & infl'n escalated)
82	Second Stage Total (real & inflation adj)
83	Transmission Line (real & infl'n escalated)
84	Gas Pipeline (real & infl'n escalated)
85	Capital Repairs
86	Office Equipment
87	2006
88	Generation Plant (real & infl'n escalated)
89	Second Stage Total (real & inflation adj)
90	Transmission Line (real & infl'n escalated)
91	Gas Pipeline (real & infl'n escalated)
92	Capital Repairs
93	Office Equipment

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DEPRECIATION / CAPITAL EXPENDITURES — Project Year

			2007	2008	2009	2010	2011	2012	2013
94	2007								
95	Generation Plant (real & infl'n escalated)	25	0						
96	Second Stage Total (real & inflation adj)	25	0						
97	Transmission Line (real & infl'n escalated)	25	0						
98	Gas Pipeline (real & infl'n escalated)	25	0						
99	Capital Repairs	25	10,062						
100	Office Equipment	7	0						
101	2008								
102	Generation Plant (real & infl'n escalated)	25		0					
103	Second Stage Total (real & inflation adj)	25		0					
104	Transmission Line (real & infl'n escalated)	25		0					
105	Gas Pipeline (real & infl'n escalated)	25		0					
106	Capital Repairs	25		10,489					
107	Office Equipment	7		0					
108	2009								
109	Generation Plant (real & infl'n escalated)	25			0				
110	Second Stage Total (real & inflation adj)	25			0				
111	Transmission Line (real & infl'n escalated)	25			0				
112	Gas Pipeline (real & infl'n escalated)	25			0				
113	Capital Repairs	25			10,934				
114	Office Equipment	7			0				
115	2010								
116	Generation Plant (real & infl'n escalated)	25				0			
117	Second Stage Total (real & inflation adj)	25				0			
118	Transmission Line (real & infl'n escalated)	25				0			
119	Gas Pipeline (real & infl'n escalated)	25				0			
120	Capital Repairs	25				11,398			
121	Office Equipment	7				0			
122	2011								
123	Generation Plant (real & infl'n escalated)	25					0		
124	Second Stage Total (real & inflation adj)	25					0		
125	Transmission Line (real & infl'n escalated)	25					0		
126	Gas Pipeline (real & infl'n escalated)	25					0		
127	Capital Repairs	25					11,882		
128	Office Equipment	7					0		
129	2012								
130	Generation Plant (real & infl'n escalated)	25						0	
131	Second Stage Total (real & inflation adj)	25						0	
132	Transmission Line (real & infl'n escalated)	25						0	
133	Gas Pipeline (real & infl'n escalated)	25						0	
134	Capital Repairs	25						12,387	
135	Office Equipment	7						0	
136	2013								
137	Generation Plant (real & infl'n escalated)	25							0
138	Second Stage Total (real & inflation adj)	25							0
139	Transmission Line (real & infl'n escalated)	25							0
140	Gas Pipeline (real & infl'n escalated)	25							0
141	Capital Repairs	25							12,912
142	Office Equipment	7							0

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	DEPRECIATION & CAPITAL EXPENDITURES	2014	2015	2016	2017	2018	2019	2020	2021	2022	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
		19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	[illegible]	[illegible]	[illegible]	[illegible]
94	2007																				
95	Generation Plant (real & infl'n escalated)																				
96	Second Stage Total (real & inflation adj)																				
97	Transmission Line (real & infl'n escalated)																				
98	Gas Pipeline (real & infl'n escalated)																				
99	Capital Repairs																				
100	Office Equipment																				
101	2008																				
102	Generation Plant (real & infl'n escalated)																				
103	Second Stage Total (real & inflation adj)																				
104	Transmission Line (real & infl'n escalated)																				
105	Gas Pipeline (real & infl'n escalated)																				
106	Capital Repairs																				
107	Office Equipment																				
108	2009																				
109	Generation Plant (real & infl'n escalated)																				
110	Second Stage Total (real & inflation adj)																				
111	Transmission Line (real & infl'n escalated)																				
112	Gas Pipeline (real & infl'n escalated)																				
113	Capital Repairs																				
114	Office Equipment																				
115	2010																				
116	Generation Plant (real & infl'n escalated)																				
117	Second Stage Total (real & inflation adj)																				
118	Transmission Line (real & infl'n escalated)																				
119	Gas Pipeline (real & infl'n escalated)																				
120	Capital Repairs																				
121	Office Equipment																				
122	2011																				
123	Generation Plant (real & infl'n escalated)																				
124	Second Stage Total (real & inflation adj)																				
125	Transmission Line (real & infl'n escalated)																				
126	Gas Pipeline (real & infl'n escalated)																				
127	Capital Repairs																				
128	Office Equipment																				
129	2012																				
130	Generation Plant (real & infl'n escalated)																				
131	Second Stage Total (real & inflation adj)																				
132	Transmission Line (real & infl'n escalated)																				
133	Gas Pipeline (real & infl'n escalated)																				
134	Capital Repairs																				
135	Office Equipment																				
136	2013																				
137	Generation Plant (real & infl'n escalated)																				
138	Second Stage Total (real & inflation adj)																				
139	Transmission Line (real & infl'n escalated)																				
140	Gas Pipeline (real & infl'n escalated)																				
141	Capital Repairs																				
142	Office Equipment																				

143	2014	
144	Generation Plant (real & infl'n escalated)	25
145	Second Stage Total (real & inflation adj)	25
146	Transmission Line (real & infl'n escalated)	25
147	Gas Pipeline (real & infl'n escalated)	25
148	Capital Repairs	25
149	Office Equipment	7
150	2015	
151	Generation Plant (real & infl'n escalated)	25
152	Second Stage Total (real & inflation adj)	25
153	Transmission Line (real & infl'n escalated)	25
154	Gas Pipeline (real & infl'n escalated)	25
155	Capital Repairs	25
156	Office Equipment	7
157	2016	
158	Generation Plant (real & infl'n escalated)	25
159	Second Stage Total (real & inflation adj)	25
160	Transmission Line (real & infl'n escalated)	25
161	Gas Pipeline (real & infl'n escalated)	25
162	Capital Repairs	25
163	Office Equipment	7
164	2017	
165	Generation Plant (real & infl'n escalated)	25
166	Second Stage Total (real & inflation adj)	25
167	Transmission Line (real & infl'n escalated)	25
168	Gas Pipeline (real & infl'n escalated)	25
169	Capital Repairs	25
170	Office Equipment	7
171	2018	
172	Generation Plant (real & infl'n escalated)	25
173	Second Stage Total (real & inflation adj)	25
174	Transmission Line (real & infl'n escalated)	25
175	Gas Pipeline (real & infl'n escalated)	25
176	Capital Repairs	25
177	Office Equipment	7
178	2019	
179	Generation Plant (real & infl'n escalated)	25
180	Second Stage Total (real & inflation adj)	25
181	Transmission Line (real & infl'n escalated)	25
182	Gas Pipeline (real & infl'n escalated)	25
183	Capital Repairs	25
184	Office Equipment	7
185	2020	
186	Generation Plant (real & infl'n escalated)	25
187	Second Stage Total (real & inflation adj)	25
188	Transmission Line (real & infl'n escalated)	25
189	Gas Pipeline (real & infl'n escalated)	25
190	Capital Repairs	25
191	Office Equipment	7

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DEPRECIATION & CAPITAL EXPENDITURES

		2014	2015	2016	2017	2018	2019	2020
143	2014	2014						
144	Generation Plant (real & infl'n escalated)	0						
145	Second Stage Total (real & inflation adj)	0						
146	Transmission Line (real & infl'n escalated)	0						
147	Gas Pipeline (real & infl'n escalated)	0						
148	Capital Repairs	13,460						
149	Office Equipment	0						
150	2015		2015					
151	Generation Plant (real & infl'n escalated)		0					
152	Second Stage Total (real & inflation adj)		0					
153	Transmission Line (real & infl'n escalated)		0					
154	Gas Pipeline (real & infl'n escalated)		0					
155	Capital Repairs		14,032					
156	Office Equipment		0					
157	2016			2016				
158	Generation Plant (real & infl'n escalated)			0				
159	Second Stage Total (real & inflation adj)			0				
160	Transmission Line (real & infl'n escalated)			0				
161	Gas Pipeline (real & infl'n escalated)			0				
162	Capital Repairs			14,627				
163	Office Equipment			0				
164	2017				2017			
165	Generation Plant (real & infl'n escalated)				0			
166	Second Stage Total (real & inflation adj)				0			
167	Transmission Line (real & infl'n escalated)				0			
168	Gas Pipeline (real & infl'n escalated)				0			
169	Capital Repairs				15,248			
170	Office Equipment				0			
171	2018					2018		
172	Generation Plant (real & infl'n escalated)					0		
173	Second Stage Total (real & inflation adj)					0		
174	Transmission Line (real & infl'n escalated)					0		
175	Gas Pipeline (real & infl'n escalated)					0		
176	Capital Repairs					15,895		
177	Office Equipment					0		
178	2019						2019	
179	Generation Plant (real & infl'n escalated)						0	
180	Second Stage Total (real & inflation adj)						0	
181	Transmission Line (real & infl'n escalated)						0	
182	Gas Pipeline (real & infl'n escalated)						0	
183	Capital Repairs						16,570	
184	Office Equipment						0	
185	2020							2020
186	Generation Plant (real & infl'n escalated)							0
187	Second Stage Total (real & inflation adj)							0
188	Transmission Line (real & infl'n escalated)							0
189	Gas Pipeline (real & infl'n escalated)							0
190	Capital Repairs							17,273
191	Office Equipment							0

		Project Year
192	2021	
193	Generation Plant (real & infl'n escalated)	25
194	Second Stage Total (real & inflation adj)	25
195	Transmission Line (real & infl'n escalated)	25
196	Gas Pipeline (real & infl'n escalated)	25
197	Capital Repairs	25
198	Office Equipment	7
199	2022	
200	Generation Plant (real & infl'n escalated)	25
201	Second Stage Total (real & inflation adj)	25
202	Transmission Line (real & infl'n escalated)	25
203	Gas Pipeline (real & infl'n escalated)	25
204	Capital Repairs	25
205	Office Equipment	7
206	2023	
207	Generation Plant (real & infl'n escalated)	25
208	Second Stage Total (real & inflation adj)	25
209	Transmission Line (real & infl'n escalated)	25
210	Gas Pipeline (real & infl'n escalated)	25
211	Capital Repairs	25
212	Office Equipment	7
213	2024	
214	Generation Plant (real & infl'n escalated)	25
215	Second Stage Total (real & inflation adj)	25
216	Transmission Line (real & infl'n escalated)	25
217	Gas Pipeline (real & infl'n escalated)	25
218	Capital Repairs	25
219	Office Equipment	7
220	2025	
221	Generation Plant (real & infl'n escalated)	25
222	Second Stage Total (real & inflation adj)	25
223	Transmission Line (real & infl'n escalated)	25
224	Gas Pipeline (real & infl'n escalated)	25
225	Capital Repairs	25
226	Office Equipment	7
227	2026	
228	Generation Plant (real & infl'n escalated)	25
229	Second Stage Total (real & inflation adj)	25
230	Transmission Line (real & infl'n escalated)	25
231	Gas Pipeline (real & infl'n escalated)	25
232	Capital Repairs	25
233	Office Equipment	7
234	2027	
235	Generation Plant (real & infl'n escalated)	25
236	Second Stage Total (real & inflation adj)	25
237	Transmission Line (real & infl'n escalated)	25
238	Gas Pipeline (real & infl'n escalated)	25
239	Capital Repairs	25
240	Office Equipment	7

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192	2021	2021
193	Generation Plant (real & infl'n escalated)	0
194	Second Stage Total (real & inflation adj)	0
195	Transmission Line (real & infl'n escalated)	0
196	Gas Pipeline (real & infl'n escalated)	0
197	Capital Repairs	18,006
198	Office Equipment	0
199	2022	2022
200	Generation Plant (real & infl'n escalated)	0
201	Second Stage Total (real & inflation adj)	0
202	Transmission Line (real & infl'n escalated)	0
203	Gas Pipeline (real & infl'n escalated)	0
204	Capital Repairs	18,770
205	Office Equipment	0
206	2023	2023
207	Generation Plant (real & infl'n escalated)	0
208	Second Stage Total (real & inflation adj)	0
209	Transmission Line (real & infl'n escalated)	0
210	Gas Pipeline (real & infl'n escalated)	0
211	Capital Repairs	19,567
212	Office Equipment	0
213	2024	2024
214	Generation Plant (real & infl'n escalated)	0
215	Second Stage Total (real & inflation adj)	0
216	Transmission Line (real & infl'n escalated)	0
217	Gas Pipeline (real & infl'n escalated)	0
218	Capital Repairs	20,397
219	Office Equipment	0
220	2025	2025
221	Generation Plant (real & infl'n escalated)	0
222	Second Stage Total (real & inflation adj)	0
223	Transmission Line (real & infl'n escalated)	0
224	Gas Pipeline (real & infl'n escalated)	0
225	Capital Repairs	21,263
226	Office Equipment	0
227	2026	2026
228	Generation Plant (real & infl'n escalated)	0
229	Second Stage Total (real & inflation adj)	0
230	Transmission Line (real & infl'n escalated)	0
231	Gas Pipeline (real & infl'n escalated)	0
232	Capital Repairs	22,165
233	Office Equipment	0
234	2027	2027
235	Generation Plant (real & infl'n escalated)	0
236	Second Stage Total (real & inflation adj)	0
237	Transmission Line (real & infl'n escalated)	0
238	Gas Pipeline (real & infl'n escalated)	0
239	Capital Repairs	23,106
240	Office Equipment	0

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DEPRECIATION & CAPITAL EXPENDITURES [illegible]

241	2028	
242	Generation Plant (real & infl'n escalated)	25
243	Second Stage Total (real & inflation adj)	25
244	Transmission Line (real & infl'n escalated)	25
245	Gas Pipeline (real & infl'n escalated)	25
246	Capital Repairs	25
247	Office Equipment	7
248	2029	
249	Generation Plant (real & infl'n escalated)	25
250	Second Stage Total (real & inflation adj)	25
251	Transmission Line (real & infl'n escalated)	25
252	Gas Pipeline (real & infl'n escalated)	25
253	Capital Repairs	25
254	Office Equipment	7
255	2030	
256	Generation Plant (real & infl'n escalated)	25
257	Second Stage Total (real & inflation adj)	25
258	Transmission Line (real & infl'n escalated)	25
259	Gas Pipeline (real & infl'n escalated)	25
260	Capital Repairs	25
261	Office Equipment	7
262	2031	
263	Generation Plant (real & infl'n escalated)	25
264	Second Stage Total (real & inflation adj)	25
265	Transmission Line (real & infl'n escalated)	25
266	Gas Pipeline (real & infl'n escalated)	25
267	Capital Repairs	25
268	Office Equipment	7
269	2032	
270	Generation Plant (real & infl'n escalated)	25
271	Second Stage Total (real & inflation adj)	25
272	Transmission Line (real & infl'n escalated)	25
273	Gas Pipeline (real & infl'n escalated)	25
274	Capital Repairs	25
275	Office Equipment	7
276	2033	
277	Generation Plant (real & infl'n escalated)	25
278	Second Stage Total (real & inflation adj)	25
279	Transmission Line (real & infl'n escalated)	25
280	Gas Pipeline (real & infl'n escalated)	25
281	Capital Repairs	25
282	Office Equipment	7
283	2034	
284	Generation Plant (real & infl'n escalated)	25
285	Second Stage Total (real & inflation adj)	25
286	Transmission Line (real & infl'n escalated)	25
287	Gas Pipeline (real & infl'n escalated)	25
288	Capital Repairs	25
289	Office Equipment	7
290		

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DEPRECIATION & CAPITAL EXPENDITURES

241	2028	2028						
242	Generation Plant (real & infl'n escalated)	0						
243	Second Stage Total (real & inflation adj)	0						
244	Transmission Line (real & infl'n escalated)	0						
245	Gas Pipeline (real & infl'n escalated)	0						
246	Capital Repairs	24,086						
247	Office Equipment	0						
248	2029		2029					
249	Generation Plant (real & infl'n escalated)		0					
250	Second Stage Total (real & inflation adj)		0					
251	Transmission Line (real & infl'n escalated)		0					
252	Gas Pipeline (real & infl'n escalated)		0					
253	Capital Repairs		25,109					
254	Office Equipment		0					
255	2030			2030				
256	Generation Plant (real & infl'n escalated)			0				
257	Second Stage Total (real & inflation adj)			0				
258	Transmission Line (real & infl'n escalated)			0				
259	Gas Pipeline (real & infl'n escalated)			0				
260	Capital Repairs			26,174				
261	Office Equipment			0				
262	2031				2031			
263	Generation Plant (real & infl'n escalated)				0			
264	Second Stage Total (real & inflation adj)				0			
265	Transmission Line (real & infl'n escalated)				0			
266	Gas Pipeline (real & infl'n escalated)				0			
267	Capital Repairs				27,285			
268	Office Equipment				0			
269	2032					2032		
270	Generation Plant (real & infl'n escalated)					0		
271	Second Stage Total (real & inflation adj)					0		
272	Transmission Line (real & infl'n escalated)					0		
273	Gas Pipeline (real & infl'n escalated)					0		
274	Capital Repairs					28,443		
275	Office Equipment					0		
276	2033						2033	
277	Generation Plant (real & infl'n escalated)						0	
278	Second Stage Total (real & inflation adj)						0	
279	Transmission Line (real & infl'n escalated)						0	
280	Gas Pipeline (real & infl'n escalated)						0	
281	Capital Repairs						29,650	
282	Office Equipment						0	
283	2034							2034
284	Generation Plant (real & infl'n escalated)							0
285	Second Stage Total (real & inflation adj)							0
286	Transmission Line (real & infl'n escalated)							0
287	Gas Pipeline (real & infl'n escalated)							0
288	Capital Repairs							30,909
289	Office Equipment							0
290								

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	[illegible]																			
291	[illegible]																			
292																				
293																				
294	[illegible]																			
295	1996																			
296	Generation Plant (real & infl'n escalated)	25	0	0	752	1,503	1,503	1,503	1,503	1,503	1,503	1,503	1,503	1,503	1,503	1,503	1,503	1,503	1,503	1,503
297	Second Stage Total (real & inflation adj)	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
298	Transmission Line (real & infl'n escalated)	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
299	Gas Pipeline (real & infl'n escalated)	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
300	Capital Repairs	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
301	Office Equipment	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
302	1997																			
303	Generation Plant (real & infl'n escalated)	25		0	3,193	6,385	6,385	6,385	6,385	6,385	6,385	6,385	6,385	6,385	6,385	6,385	6,385	6,385	6,385	6,385
304	Second Stage Total (real & inflation adj)	25		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
305	Transmission Line (real & infl'n escalated)	25		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
306	Gas Pipeline (real & infl'n escalated)	25		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
307	Capital Repairs	25		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
308	Office Equipment	7		0	135	270	270	270	270	270	270	135	0	0	0	0	0	0	0	0
309	1998																			
310	Generation Plant (real & infl'n escalated)	25			4,866	9,732	9,732	9,732	9,732	9,732	9,732	9,732	9,732	9,732	9,732	9,732	9,732	9,732	9,732	9,732
311	Second Stage Total (real & inflation adj)	25			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
312	Transmission Line (real & infl'n escalated)	25			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
313	Gas Pipeline (real & infl'n escalated)	25			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
314	Capital Repairs	25			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
315	Office Equipment	7			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
316	1999																			
317	Generation Plant (real & infl'n escalated)	25				4,381	8,762	8,762	8,762	8,762	8,762	8,762	8,762	8,762	8,762	8,762	8,762	8,762	8,762	8,762
318	Second Stage Total (real & inflation adj)	25				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
319	Transmission Line (real & infl'n escalated)	25				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
320	Gas Pipeline (real & infl'n escalated)	25				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
321	Capital Repairs	25				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
322	Office Equipment	7				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
323	2000																			
324	Generation Plant (real & infl'n escalated)	25					1,913	3,825	3,825	3,825	3,825	3,825	3,825	3,825	3,825	3,825	3,825	3,825	3,825	3,825
325	Second Stage Total (real & inflation adj)	25					0	0	0	0	0	0	0	0	0	0	0	0	0	0
326	Transmission Line (real & infl'n escalated)	25					0	0	0	0	0	0	0	0	0	0	0	0	0	0
327	Gas Pipeline (real & infl'n escalated)	25					0	0	0	0	0	0	0	0	0	0	0	0	0	0
328	Capital Repairs	25					0	0	0	0	0	0	0	0	0	0	0	0	0	0
329	Office Equipment	7					0	0	0	0	0	0	0	0	0	0	0	0	0	0
330	2001																			
331	Generation Plant (real & infl'n escalated)	25						0	0	0	0	0	0	0	0	0	0	0	0	0
332	Second Stage Total (real & inflation adj)	25						0	0	0	0	0	0	0	0	0	0	0	0	0
333	Transmission Line (real & infl'n escalated)	25						0	0	0	0	0	0	0	0	0	0	0	0	0
334	Gas Pipeline (real & infl'n escalated)	25						0	0	0	0	0	0	0	0	0	0	0	0	0
335	Capital Repairs	25						31	63	63	63	63	63	63	63	63	63	63	63	63
336	Office Equipment	7						0	0	0	0	0	0	0	0	0	0	0	0	0

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	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
291	[illegible]																					
292																						
293																						
294	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
295	1996																					
296	Generation Plant (real & inf'n escalated)	1,503	1,503	1,503	1,503	1,503	1,503	1,503	1,503	1,503	752	0	0	0	0	0	0	0	0	0	0	0
297	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
298	Transmission Line (real & inf'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
299	Gas Pipeline (real & inf'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
300	Capital Repairs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
301	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
302	1997																					
303	Generation Plant (real & inf'n escalated)	6,385	6,385	6,385	6,385	6,385	6,385	6,385	6,385	6,385	3,193	0	0	0	0	0	0	0	0	0	0	0
304	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
305	Transmission Line (real & inf'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
306	Gas Pipeline (real & inf'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
307	Capital Repairs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
308	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
309	1998																					
310	Generation Plant (real & inf'n escalated)	9,732	9,732	9,732	9,732	9,732	9,732	9,732	9,732	9,732	4,866	0	0	0	0	0	0	0	0	0	0	0
311	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
312	Transmission Line (real & inf'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
313	Gas Pipeline (real & inf'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
314	Capital Repairs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
315	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
316	1999																					
317	Generation Plant (real & inf'n escalated)	8,762	8,762	8,762	8,762	8,762	8,762	8,762	8,762	8,762	8,762	4,381	0	0	0	0	0	0	0	0	0	0
318	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
319	Transmission Line (real & inf'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
320	Gas Pipeline (real & inf'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
321	Capital Repairs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
322	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
323	2000																					
324	Generation Plant (real & inf'n escalated)	3,825	3,825	3,825	3,825	3,825	3,825	3,825	3,825	3,825	3,825	3,825	1,913	0	0	0	0	0	0	0	0	0
325	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
326	Transmission Line (real & inf'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
327	Gas Pipeline (real & inf'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
328	Capital Repairs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
329	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
330	2001																					
331	Generation Plant (real & inf'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
332	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
333	Transmission Line (real & inf'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
334	Gas Pipeline (real & inf'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
335	Capital Repairs	63	63	63	63	63	63	63	63	63	63	63	63	31	0	0	0	0	0	0	0	0
336	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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337	2002														
338	Generation Plant (real & infl'n escalated)	25	0	0	0	0	0	0	0	0	0	0	0	0
339	Second Stage Total (real & inflation adj)	25	0	0	0	0	0	0	0	0	0	0	0	0
340	Transmission Line (real & infl'n escalated)	25	0	0	0	0	0	0	0	0	0	0	0	0
341	Gas Pipeline (real & infl'n escalated)	25	0	0	0	0	0	0	0	0	0	0	0	0
342	Capital Repairs	25	66	131	131	131	131	131	131	131	131	131	131	131
343	Office Equipment	7	0	0	0	0	0	0	0	0	0	0	0	0
344	2003													
345	Generation Plant (real & infl'n escalated)	25		0	0	0	0	0	0	0	0	0	0	0
346	Second Stage Total (real & inflation adj)	25		0	0	0	0	0	0	0	0	0	0	0
347	Transmission Line (real & infl'n escalated)	25		0	0	0	0	0	0	0	0	0	0	0
348	Gas Pipeline (real & infl'n escalated)	25		0	0	0	0	0	0	0	0	0	0	0
349	Capital Repairs	25		102	205	205	205	205	205	205	205	205	205	205
350	Office Equipment	7		0	0	0	0	0	0	0	0	0	0	0
351	2004													
352	Generation Plant (real & infl'n escalated)	25			0	0	0	0	0	0	0	0	0	0
353	Second Stage Total (real & inflation adj)	25			0	0	0	0	0	0	0	0	0	0
354	Transmission Line (real & infl'n escalated)	25			0	0	0	0	0	0	0	0	0	0
355	Gas Pipeline (real & infl'n escalated)	25			0	0	0	0	0	0	0	0	0	0
356	Capital Repairs	25			142	284	284	284	284	284	284	284	284	284
357	Office Equipment	7			0	0	0	0	0	0	0	0	0	0
358	2005													
359	Generation Plant (real & infl'n escalated)	25				0	0	0	0	0	0	0	0	0
360	Second Stage Total (real & inflation adj)	25				0	0	0	0	0	0	0	0	0
361	Transmission Line (real & infl'n escalated)	25				0	0	0	0	0	0	0	0	0
362	Gas Pipeline (real & infl'n escalated)	25				0	0	0	0	0	0	0	0	0
363	Capital Repairs	25				185	370	370	370	370	370	370	370	370
364	Office Equipment	7				0	0	0	0	0	0	0	0	0
365	2006													
366	Generation Plant (real & infl'n escalated)	25					0	0	0	0	0	0	0	0
367	Second Stage Total (real & inflation adj)	25					0	0	0	0	0	0	0	0
368	Transmission Line (real & infl'n escalated)	25					0	0	0	0	0	0	0	0
369	Gas Pipeline (real & infl'n escalated)	25					0	0	0	0	0	0	0	0
370	Capital Repairs	25					193	386	386	386	386	386	386	386
371	Office Equipment	7					0	0	0	0	0	0	0	0
372	2007													
373	Generation Plant (real & infl'n escalated)	25						0	0	0	0	0	0	0
374	Second Stage Total (real & inflation adj)	25						0	0	0	0	0	0	0
375	Transmission Line (real & infl'n escalated)	25						0	0	0	0	0	0	0
376	Gas Pipeline (real & infl'n escalated)	25						0	0	0	0	0	0	0
377	Capital Repairs	25						201	402	402	402	402	402	402
378	Office Equipment	7						0	0	0	0	0	0	0
379	2008													
380	Generation Plant (real & infl'n escalated)	25							0	0	0	0	0	0
381	Second Stage Total (real & inflation adj)	25							0	0	0	0	0	0
382	Transmission Line (real & infl'n escalated)	25							0	0	0	0	0	0
383	Gas Pipeline (real & infl'n escalated)	25							0	0	0	0	0	0
384	Capital Repairs	25							210	420	420	420	420	420
385	Office Equipment	7							0	0	0	0	0	0

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	DEPRECIATION & CAPITAL EXPENDITURE	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
337	2002																					
338	Generation Plant (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
339	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
340	Transmission Line (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
341	Gas Pipeline (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
342	Capital Repairs	131	131	131	131	131	131	131	131	131	131	131	131	131	66	0	0	0	0	0	0	0
343	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
344	2003																					
345	Generation Plant (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
346	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
347	Transmission Line (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
348	Gas Pipeline (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
349	Capital Repairs	205	205	205	205	205	205	205	205	205	205	205	205	205	205	102	0	0	0	0	0	0
350	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
351	2004																					
352	Generation Plant (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
353	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
354	Transmission Line (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
355	Gas Pipeline (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
356	Capital Repairs	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	142	0	0	0	0	0
357	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
358	2005																					
359	Generation Plant (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
360	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
361	Transmission Line (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
362	Gas Pipeline (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
363	Capital Repairs	370	370	370	370	370	370	370	370	370	370	370	370	370	370	370	370	185	0	0	0	0
364	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
365	2006																					
366	Generation Plant (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
367	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
368	Transmission Line (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
369	Gas Pipeline (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
370	Capital Repairs	386	386	386	386	386	386	386	386	386	386	386	386	386	386	386	386	386	193	0	0	0
371	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
372	2007																					
373	Generation Plant (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
374	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
375	Transmission Line (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
376	Gas Pipeline (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
377	Capital Repairs	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	201	0	0
378	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
379	2008																					
380	Generation Plant (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
381	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
382	Transmission Line (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
383	Gas Pipeline (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
384	Capital Repairs	420	420	420	420	420	420	420	420	420	420	420	420	420	420	420	420	420	420	420	210	0
385	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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DEPRECIATION & CAPITAL EXPENDITURES

386	2009						
387	Generation Plant (real & infl'n escalated)	25	0	0	0	0	0
388	Second Stage Total (real & inflation adj)	25	0	0	0	0	0
389	Transmission Line (real & infl'n escalated)	25	0	0	0	0	0
390	Gas Pipeline (real & infl'n escalated)	25	0	0	0	0	0
391	Capital Repairs	25	219	437	437	437	437
392	Office Equipment	7	0	0	0	0	0
393	2010						
394	Generation Plant (real & infl'n escalated)	25		0	0	0	0
395	Second Stage Total (real & inflation adj)	25		0	0	0	0
396	Transmission Line (real & infl'n escalated)	25		0	0	0	0
397	Gas Pipeline (real & infl'n escalated)	25		0	0	0	0
398	Capital Repairs	25		228	456	456	456
399	Office Equipment	7		0	0	0	0
400	2011						
401	Generation Plant (real & infl'n escalated)	25			0	0	0
402	Second Stage Total (real & inflation adj)	25			0	0	0
403	Transmission Line (real & infl'n escalated)	25			0	0	0
404	Gas Pipeline (real & infl'n escalated)	25			0	0	0
405	Capital Repairs	25			238	475	475
406	Office Equipment	7			0	0	0
407	2012						
408	Generation Plant (real & infl'n escalated)	25				0	0
409	Second Stage Total (real & inflation adj)	25				0	0
410	Transmission Line (real & infl'n escalated)	25				0	0
411	Gas Pipeline (real & infl'n escalated)	25				0	0
412	Capital Repairs	25				248	495
413	Office Equipment	7				0	0
414	2013						
415	Generation Plant (real & infl'n escalated)	25					0
416	Second Stage Total (real & inflation adj)	25					0
417	Transmission Line (real & infl'n escalated)	25					0
418	Gas Pipeline (real & infl'n escalated)	25					0
419	Capital Repairs	25					258
420	Office Equipment	7					0
421	2014						
422	Generation Plant (real & infl'n escalated)	25					
423	Second Stage Total (real & inflation adj)	25					
424	Transmission Line (real & infl'n escalated)	25					
425	Gas Pipeline (real & infl'n escalated)	25					
426	Capital Repairs	25					
427	Office Equipment	7					
428	2015						
429	Generation Plant (real & infl'n escalated)	25					
430	Second Stage Total (real & inflation adj)	25					
431	Transmission Line (real & infl'n escalated)	25					
432	Gas Pipeline (real & infl'n escalated)	25					
433	Capital Repairs	25					
434	Office Equipment	7					

386	2009																					
387	Generation Plant (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
388	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
389	Transmission Line (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
390	Gas Pipeline (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
391	Capital Repairs	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437	219
392	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
393	2010																					
394	Generation Plant (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
395	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
396	Transmission Line (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
397	Gas Pipeline (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
398	Capital Repairs	456	456	456	456	456	456	456	456	456	456	456	456	456	456	456	456	456	456	456	456	456
399	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
400	2011																					
401	Generation Plant (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
402	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
403	Transmission Line (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
404	Gas Pipeline (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
405	Capital Repairs	475	475	475	475	475	475	475	475	475	475	475	475	475	475	475	475	475	475	475	475	475
406	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
407	2012																					
408	Generation Plant (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
409	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
410	Transmission Line (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
411	Gas Pipeline (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
412	Capital Repairs	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495
413	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
414	2013																					
415	Generation Plant (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
416	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
417	Transmission Line (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
418	Gas Pipeline (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
419	Capital Repairs	516	516	516	516	516	516	516	516	516	516	516	516	516	516	516	516	516	516	516	516	516
420	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
421	2014																					
422	Generation Plant (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
423	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
424	Transmission Line (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
425	Gas Pipeline (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
426	Capital Repairs	289	538	538	538	538	538	538	538	538	538	538	538	538	538	538	538	538	538	538	538	538
427	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
428	2015																					
429	Generation Plant (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
430	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
431	Transmission Line (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
432	Gas Pipeline (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
433	Capital Repairs	281	561	561	561	561	561	561	561	561	561	561	561	561	561	561	561	561	561	561	561	561
434	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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435	2016	
436	Generation Plant (real & infl'n escalated)	25
437	Second Stage Total (real & inflation adj)	25
438	Transmission Line (real & infl'n escalated)	25
439	Gas Pipeline (real & infl'n escalated)	25
440	Capital Repairs	25
441	Office Equipment	7
442	2017	
443	Generation Plant (real & infl'n escalated)	25
444	Second Stage Total (real & inflation adj)	25
445	Transmission Line (real & infl'n escalated)	25
446	Gas Pipeline (real & infl'n escalated)	25
447	Capital Repairs	25
448	Office Equipment	7
449	2018	
450	Generation Plant (real & infl'n escalated)	25
451	Second Stage Total (real & inflation adj)	25
452	Transmission Line (real & infl'n escalated)	25
453	Gas Pipeline (real & infl'n escalated)	25
454	Capital Repairs	25
455	Office Equipment	7
456	2019	
457	Generation Plant (real & infl'n escalated)	25
458	Second Stage Total (real & inflation adj)	25
459	Transmission Line (real & infl'n escalated)	25
460	Gas Pipeline (real & infl'n escalated)	25
461	Capital Repairs	25
462	Office Equipment	7
463	2020	
464	Generation Plant (real & infl'n escalated)	25
465	Second Stage Total (real & inflation adj)	25
466	Transmission Line (real & infl'n escalated)	25
467	Gas Pipeline (real & infl'n escalated)	25
468	Capital Repairs	25
469	Office Equipment	7
470	2021	
471	Generation Plant (real & infl'n escalated)	25
472	Second Stage Total (real & inflation adj)	25
473	Transmission Line (real & infl'n escalated)	25
474	Gas Pipeline (real & infl'n escalated)	25
475	Capital Repairs	25
476	Office Equipment	7
477	2022	
478	Generation Plant (real & infl'n escalated)	25
479	Second Stage Total (real & inflation adj)	25
480	Transmission Line (real & infl'n escalated)	25
481	Gas Pipeline (real & infl'n escalated)	25
482	Capital Repairs	25
483	Office Equipment	7

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	[illegible]	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39
435	2016																					
436	Generation Plant (real & infl'n escalated)			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
437	Second Stage Total (real & inflation adj)			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
438	Transmission Line (real & infl'n escalated)			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
439	Gas Pipeline (real & infl'n escalated)			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
440	Capital Repairs			293	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585
441	Office Equipment			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
442	2017																					
443	Generation Plant (real & infl'n escalated)				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
444	Second Stage Total (real & inflation adj)				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
445	Transmission Line (real & infl'n escalated)				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
446	Gas Pipeline (real & infl'n escalated)				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
447	Capital Repairs				305	610	610	610	610	610	610	610	610	610	610	610	610	610	610	610	610	610
448	Office Equipment				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
449	2018																					
450	Generation Plant (real & infl'n escalated)					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
451	Second Stage Total (real & inflation adj)					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
452	Transmission Line (real & infl'n escalated)					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
453	Gas Pipeline (real & infl'n escalated)					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
454	Capital Repairs					318	636	636	636	636	636	636	636	636	636	636	636	636	636	636	636	636
455	Office Equipment					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
456	2019																					
457	Generation Plant (real & infl'n escalated)						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
458	Second Stage Total (real & inflation adj)						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
459	Transmission Line (real & infl'n escalated)						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
460	Gas Pipeline (real & infl'n escalated)						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
461	Capital Repairs						331	663	663	663	663	663	663	663	663	663	663	663	663	663	663	663
462	Office Equipment						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
463	2020																					
464	Generation Plant (real & infl'n escalated)							0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
465	Second Stage Total (real & inflation adj)							0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
466	Transmission Line (real & infl'n escalated)							0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
467	Gas Pipeline (real & infl'n escalated)							0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
468	Capital Repairs							345	691	691	691	691	691	691	691	691	691	691	691	691	691	691
469	Office Equipment							0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
470	2021																					
471	Generation Plant (real & infl'n escalated)								0	0	0	0	0	0	0	0	0	0	0	0	0	0
472	Second Stage Total (real & inflation adj)								0	0	0	0	0	0	0	0	0	0	0	0	0	0
473	Transmission Line (real & infl'n escalated)								0	0	0	0	0	0	0	0	0	0	0	0	0	0
474	Gas Pipeline (real & infl'n escalated)								0	0	0	0	0	0	0	0	0	0	0	0	0	0
475	Capital Repairs								360	720	720	720	720	720	720	720	720	720	720	720	720	720
476	Office Equipment								0	0	0	0	0	0	0	0	0	0	0	0	0	0
477	2022																					
478	Generation Plant (real & infl'n escalated)									0	0	0	0	0	0	0	0	0	0	0	0	0
479	Second Stage Total (real & inflation adj)									0	0	0	0	0	0	0	0	0	0	0	0	0
480	Transmission Line (real & infl'n escalated)									0	0	0	0	0	0	0	0	0	0	0	0	0
481	Gas Pipeline (real & infl'n escalated)									0	0	0	0	0	0	0	0	0	0	0	0	0
482	Capital Repairs									375	751	751	751	751	751	751	751	751	751	751	751	751
483	Office Equipment									0	0	0	0	0	0	0	0	0	0	0	0	0

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484	2023	
485	Generation Plant (real & infl'n escalated)	25
486	Second Stage Total (real & inflation adj)	25
487	Transmission Line (real & infl'n escalated)	25
488	Gas Pipeline (real & infl'n escalated)	25
489	Capital Repairs	25
490	Office Equipment	7
491	2024	
492	Generation Plant (real & infl'n escalated)	25
493	Second Stage Total (real & inflation adj)	25
494	Transmission Line (real & infl'n escalated)	25
495	Gas Pipeline (real & infl'n escalated)	25
496	Capital Repairs	25
497	Office Equipment	7
498	2025	
499	Generation Plant (real & infl'n escalated)	25
500	Second Stage Total (real & inflation adj)	25
501	Transmission Line (real & infl'n escalated)	25
502	Gas Pipeline (real & infl'n escalated)	25
503	Capital Repairs	25
504	Office Equipment	7
505	2026	
506	Generation Plant (real & infl'n escalated)	25
507	Second Stage Total (real & inflation adj)	25
508	Transmission Line (real & infl'n escalated)	25
509	Gas Pipeline (real & infl'n escalated)	25
510	Capital Repairs	25
511	Office Equipment	7
512	2027	
513	Generation Plant (real & infl'n escalated)	25
514	Second Stage Total (real & inflation adj)	25
515	Transmission Line (real & infl'n escalated)	25
516	Gas Pipeline (real & infl'n escalated)	25
517	Capital Repairs	25
518	Office Equipment	7
519	2028	
520	Generation Plant (real & infl'n escalated)	25
521	Second Stage Total (real & inflation adj)	25
522	Transmission Line (real & infl'n escalated)	25
523	Gas Pipeline (real & infl'n escalated)	25
524	Capital Repairs	25
525	Office Equipment	7
526	2029	
527	Generation Plant (real & infl'n escalated)	25
528	Second Stage Total (real & inflation adj)	25
529	Transmission Line (real & infl'n escalated)	25
530	Gas Pipeline (real & infl'n escalated)	25
531	Capital Repairs	25
532	Office Equipment	7

	DEPRECIATION & CAPITAL EXPENDITURES												
484	2023												
485	Generation Plant (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0
486	Second Stage Total (real & inflation adj)	0	0	0	0	0	0	0	0	0	0	0	0
487	Transmission Line (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0
488	Gas Pipeline (real & infl'n escalated)	0	0	0	0	0	0	0	0	0	0	0	0
489	Capital Repairs	391	783	783	783	783	783	783	783	783	783	783	783
490	Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0
491	2024												
492	Generation Plant (real & infl'n escalated)		0	0	0	0	0	0	0	0	0	0	0
493	Second Stage Total (real & inflation adj)		0	0	0	0	0	0	0	0	0	0	0
494	Transmission Line (real & infl'n escalated)		0	0	0	0	0	0	0	0	0	0	0
495	Gas Pipeline (real & infl'n escalated)		0	0	0	0	0	0	0	0	0	0	0
496	Capital Repairs		408	816	816	816	816	816	816	816	816	816	816
497	Office Equipment		0	0	0	0	0	0	0	0	0	0	0
498	2025												
499	Generation Plant (real & infl'n escalated)			0	0	0	0	0	0	0	0	0	0
500	Second Stage Total (real & inflation adj)			0	0	0	0	0	0	0	0	0	0
501	Transmission Line (real & infl'n escalated)			0	0	0	0	0	0	0	0	0	0
502	Gas Pipeline (real & infl'n escalated)			0	0	0	0	0	0	0	0	0	0
503	Capital Repairs			425	851	851	851	851	851	851	851	851	851
504	Office Equipment			0	0	0	0	0	0	0	0	0	0
505	2026												
506	Generation Plant (real & infl'n escalated)				0	0	0	0	0	0	0	0	0
507	Second Stage Total (real & inflation adj)				0	0	0	0	0	0	0	0	0
508	Transmission Line (real & infl'n escalated)				0	0	0	0	0	0	0	0	0
509	Gas Pipeline (real & infl'n escalated)				0	0	0	0	0	0	0	0	0
510	Capital Repairs				443	887	887	887	887	887	887	887	887
511	Office Equipment				0	0	0	0	0	0	0	0	0
512	2027												
513	Generation Plant (real & infl'n escalated)					0	0	0	0	0	0	0	0
514	Second Stage Total (real & inflation adj)					0	0	0	0	0	0	0	0
515	Transmission Line (real & infl'n escalated)					0	0	0	0	0	0	0	0
516	Gas Pipeline (real & infl'n escalated)					0	0	0	0	0	0	0	0
517	Capital Repairs					462	924	924	924	924	924	924	924
518	Office Equipment					0	0	0	0	0	0	0	0
519	2028												
520	Generation Plant (real & infl'n escalated)						0	0	0	0	0	0	0
521	Second Stage Total (real & inflation adj)						0	0	0	0	0	0	0
522	Transmission Line (real & infl'n escalated)						0	0	0	0	0	0	0
523	Gas Pipeline (real & infl'n escalated)						0	0	0	0	0	0	0
524	Capital Repairs						482	963	963	963	963	963	963
525	Office Equipment						0	0	0	0	0	0	0
526	2029												
527	Generation Plant (real & infl'n escalated)							0	0	0	0	0	0
528	Second Stage Total (real & inflation adj)							0	0	0	0	0	0
529	Transmission Line (real & infl'n escalated)							0	0	0	0	0	0
530	Gas Pipeline (real & infl'n escalated)							0	0	0	0	0	0
531	Capital Repairs							502	1,004	1,004	1,004	1,004	1,004
532	Office Equipment							0	0	0	0	0	0

DEPRECIATION & CAPITAL EXPENDITURES [illegible]	Project Year	[illegible]
533	2030	
534	Generation Plant (real & infl'n escalated)	25
535	Second Stage Total (real & inflation adj)	25
536	Transmission Line (real & infl'n escalated)	25
537	Gas Pipeline (real & infl'n escalated)	25
538	Capital Repairs	25
539	Office Equipment	7
540	2031	
541	Generation Plant (real & infl'n escalated)	25
542	Second Stage Total (real & inflation adj)	25
543	Transmission Line (real & infl'n escalated)	25
544	Gas Pipeline (real & infl'n escalated)	25
545	Capital Repairs	25
546	Office Equipment	7
547	2032	
548	Generation Plant (real & infl'n escalated)	25
549	Second Stage Total (real & inflation adj)	25
550	Transmission Line (real & infl'n escalated)	25
551	Gas Pipeline (real & infl'n escalated)	25
552	Capital Repairs	25
553	Office Equipment	7
554	2033	
555	Generation Plant (real & infl'n escalated)	25
556	Second Stage Total (real & inflation adj)	25
557	Transmission Line (real & infl'n escalated)	25
558	Gas Pipeline (real & infl'n escalated)	25
559	Capital Repairs	25
560	Office Equipment	7
561	2034	
562	Generation Plant (real & infl'n escalated)	25
563	Second Stage Total (real & inflation adj)	25
564	Transmission Line (real & infl'n escalated)	25
565	Gas Pipeline (real & infl'n escalated)	25
566	Capital Repairs	25
567	Office Equipment	7
568		
569	Total Depreciation Expense (new)	[illegible]
570		
571	Existing Assets	[illegible]
572		
573	New Assets	[illegible]
574		
575	Total Depr Expense (new & embedded)	[illegible]
576		
577	Gross Assets	[illegible]
578		
579	Accumulated Depreciation	[illegible]
580		
581	Net Fixed Assets	[illegible]

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DEPRECIATION & CAPITAL EXPENDITURES [illegible]

533	2030					
534	Generation Plant (real & infl'n escalated)	0	0	0	0	0
535	Second Stage Total (real & inflation adj)	0	0	0	0	0
536	Transmission Line (real & infl'n escalated)	0	0	0	0	0
537	Gas Pipeline (real & infl'n escalated)	0	0	0	0	0
538	Capital Repairs	523	1,047	1,047	1,047	1,047
539	Office Equipment	0	0	0	0	0
540	2031					
541	Generation Plant (real & infl'n escalated)		0	0	0	0
542	Second Stage Total (real & inflation adj)		0	0	0	0
543	Transmission Line (real & infl'n escalated)		0	0	0	0
544	Gas Pipeline (real & infl'n escalated)		0	0	0	0
545	Capital Repairs		546	1,091	1,091	1,091
546	Office Equipment		0	0	0	0
547	2032					
548	Generation Plant (real & infl'n escalated)			0	0	0
549	Second Stage Total (real & inflation adj)			0	0	0
550	Transmission Line (real & infl'n escalated)			0	0	0
551	Gas Pipeline (real & infl'n escalated)			0	0	0
552	Capital Repairs			569	1,138	1,138
553	Office Equipment			0	0	0
554	2033					
555	Generation Plant (real & infl'n escalated)				0	0
556	Second Stage Total (real & inflation adj)				0	0
557	Transmission Line (real & infl'n escalated)				0	0
558	Gas Pipeline (real & infl'n escalated)				0	0
559	Capital Repairs				593	1,186
560	Office Equipment				0	0
561	2034					
562	Generation Plant (real & infl'n escalated)					0
563	Second Stage Total (real & inflation adj)					0
564	Transmission Line (real & infl'n escalated)					0
565	Gas Pipeline (real & infl'n escalated)					0
566	Capital Repairs					618
567	Office Equipment					0
568						
569	[illegible]	[illegible]				
570						
571	[illegible]	[illegible]				
572						
573	[illegible]	[illegible]				
574						
575	[illegible]	[illegible]				
576						
577	[illegible]	[illegible]				
578						
579	[illegible]	[illegible]				
580						
581	[illegible]	[illegible]				

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#	TAX WORKSHEET VAT and Special Tax	Project Year	1995 0	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11	2007 12	2008 13
1	**Current Year Revenues on Which VAT is Received**															
2																
3	Net Revenue (excluding VAT)		$0	$0	$0	$2,752	$59,179	$178,563	$212,548	$217,437	$221,785	$226,443	$231,198	$236,053	$241,010	$246,072
4																
5	Tax Rates															
6	VAT		20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
7	Special Tax		1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
8																
9	Tax Collections															
10	VAT		0	0	0	550	11,836	35,713	42,510	43,487	44,357	45,289	46,240	47,211	48,202	49,214
11	Special Tax		0	0	0	41	888	2,678	3,188	3,262	3,327	3,397	3,468	3,541	3,615	3,691
12	Total VAT/Special Taxes Collected		0	0	0	592	12,724	38,391	45,698	46,749	47,684	48,685	49,708	50,751	51,817	52,905
13																
14	Gross Revenues		0	0	0	3,344	71,903	216,955	258,246	264,186	269,469	275,128	280,906	286,805	292,828	298,977
15																
16	**Current Year Expenditures on Which VAT is Paid**															
17																
18	Assumption 1: Technological Import Exemption?	No														
19	Assumption 2: Year of Registration	1994														
20																
21	Operating Expenditures, Net of VAT															
22	Fixed O&M, Non-Russian, Non-Labor		0	0	0	2,635	7,056	9,012	9,770	10,507	11,208	11,915	12,620	12,987	13,358	13,733
23	Variable O&M, Russian, Non-Labor		0	0	0	78	1,706	5,202	6,239	6,428	6,600	6,781	6,965	7,125	7,289	7,457
24	Fuel Cost		0	0	0	1,615	33,102	73,167	83,790	85,717	87,431	89,268	92,054	94,927	97,889	100,944
	Accounting, Legal and Other Costs		0	0	0	529	542	554	567	581	592	605	617	630	643	657
25	Total, Net of VAT		0	0	0	4,857	42,406	87,934	100,367	103,233	105,832	108,569	112,256	115,669	119,180	122,792
26																
27	VAT and Special Tax on Operating Expenditures															
28	Fixed O&M, Non-Russian, Non-Labor		0	0	0	566	1,517	1,938	2,101	2,259	2,410	2,562	2,713	2,792	2,872	2,953
29	Variable O&M, Russian, Non-Labor		0	0	0	17	367	1,118	1,341	1,382	1,419	1,458	1,497	1,532	1,567	1,603
30	Fuel Cost		0	0	0	347	7,117	15,731	18,015	18,429	18,798	19,193	19,792	20,409	21,046	21,703
	Accounting, Legal and Other Costs		0	0	0	114	116	119	122	125	127	130	133	136	138	141
31	Total		0	0	0	1,044	9,117	18,906	21,579	22,195	22,754	23,342	24,135	24,869	25,624	26,400
32																
33	VAT Calculations, Inflation Escalated															
34	Russian Equipment		0	600	2,563	3,920	3,550	1,560	0	0	0	0	0	0	0	0
35	Russian Material		0	456	1,990	2,986	2,710	1,193	0	0	0	0	0	0	0	0
36	Russian Labor		0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Russian Indirect		0	504	2,350	3,855	3,695	1,701	0	0	0	0	0	0	0	0
38	Non-Russian Equipment		0	3,816	15,796	23,458	20,643	8,822	0	0	0	0	0	0	0	0
39	Non-Russian Indirect		0	855	3,541	5,259	4,628	1,978	0	0	0	0	0	0	0	0
	Total Office Equipment		0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Capital Repairs			0	0	0	0	0	244	499	764	1,040	1,327	1,355	1,384	1,413
40	Total VAT Calculations on Capital Expenditures		0	6,232	26,240	39,478	35,225	15,254	0	0	0	0	0	0	0	0
41																
42																

	TAX WORKSHEET VAT and Special Tax	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27	2023 28	2024 29
1	**Current Year Revenues on Which VAT is Receh**																
2																	
3	Net Revenue (excluding VAT)	$251,239	$252,667	$254,045	$255,369	$256,636	$257,844	$258,990	$260,070	$261,081	$262,020	$262,884	$263,668	$264,369	$264,983	$265,506	$265,935
4																	
5	Tax Rates																
6	VAT	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
7	Special Tax	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
8																	
9	Tax Collections																
10	VAT	50,248	50,533	50,809	51,074	51,327	51,569	51,798	52,014	52,216	52,404	52,577	52,734	52,874	52,997	53,101	53,187
11	Special Tax	3,769	3,790	3,811	3,831	3,850	3,868	3,885	3,901	3,916	3,930	3,943	3,955	3,966	3,975	3,983	3,989
12	Total VAT/Special Taxes Collected	54,016	54,324	54,620	54,904	55,177	55,437	55,683	55,915	56,133	56,334	56,520	56,689	56,839	56,971	57,084	57,176
13																	
14	Gross Revenues	305,256	306,991	308,665	310,273	311,813	313,281	314,673	315,985	317,214	318,355	319,404	320,356	321,208	321,954	322,590	323,111
15																	
16	**Current Year Expenditures on Which VAT is Pa**																
17																	
18	Assumption 1: Technological Import Exemption?																
19	Assumption 2: Year of Registration																
20																	
21	Operating Expenditures, Net of VAT																
22	Fixed O&M, Non-Russian, Non-Labor	14,115	14,501	14,895	15,295	15,701	16,114	16,534	16,962	17,396	17,839	18,290	18,749	19,151	19,562	19,982	20,411
23	Variable O&M, Russian, Non-Labor	7,627	7,685	7,742	7,798	7,852	7,904	7,954	8,001	8,047	8,090	8,131	8,169	8,201	8,230	8,256	8,279
24	Fuel Cost	104,095	105,733	107,373	109,012	110,648	112,281	113,908	115,527	117,136	118,732	120,315	121,880	123,427	124,950	126,449	127,920
	Accounting, Legal and Other Costs	671	685	699	714	729	744	760	776	792	809	826	843	861	879	897	916
25	Total, Net of VAT	126,508	128,604	130,709	132,818	134,930	137,043	139,155	141,265	143,371	145,470	147,561	149,641	151,639	153,621	155,585	157,526
26																	
27	VAT and Special Tax on Operating Expenditures																
28	Fixed O&M, Non-Russian, Non-Labor	3,035	3,118	3,202	3,288	3,376	3,465	3,555	3,647	3,740	3,835	3,932	4,031	4,117	4,206	4,296	4,388
29	Variable O&M, Russian, Non-Labor	1,640	1,652	1,665	1,677	1,688	1,699	1,710	1,720	1,730	1,739	1,748	1,756	1,763	1,769	1,775	1,780
30	Fuel Cost	22,380	22,733	23,085	23,438	23,789	24,140	24,490	24,838	25,184	25,527	25,868	26,204	26,537	26,864	27,187	27,503
	Accounting, Legal and Other Costs	144	147	150	154	157	160	163	167	170	174	178	181	185	189	193	197
31	Total	27,199	27,650	28,102	28,556	29,010	29,464	29,918	30,372	30,825	31,276	31,726	32,173	32,602	33,029	33,451	33,868
32																	
33	VAT Calculations, Inflation Escalated																
34	Russian Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Russian Material	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Russian Labor	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Russian Indirect	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Non-Russian Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39	Non-Russian Indirect	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total Office Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Capital Repairs	1,442	1,473	1,503	1,535	1,567	1,600	1,634	1,668	1,703	1,739	1,775	1,813	1,851	1,890	1,929	1,970
40	Total VAT Calculations on Capital Expenditures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
41																	
42																	

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	TAX WORKSHEET VAT and Special Tax	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39
1	**Current Year Revenues on Which VAT is Receh**										
2											
3	Net Revenue (excluding VAT)	$266,264	$266,490	$266,608	$266,614	$266,502	$266,268	$265,906	$265,412	$264,780	$264,004
4											
5	Tax Rates										
6	VAT	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
7	Special Tax	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
8											
9	Tax Collections										
10	VAT	53,253	53,298	53,322	53,323	53,300	53,254	53,181	53,082	52,956	52,801
11	Special Tax	3,994	3,997	3,999	3,999	3,998	3,994	3,989	3,981	3,972	3,960
12	Total VAT/Special Taxes Collected	57,247	57,295	57,321	57,322	57,298	57,248	57,170	57,064	56,928	56,761
13											
14	Gross Revenues	323,511	323,786	323,929	323,936	323,800	323,515	323,076	322,476	321,708	320,765
15											
16	**Current Year Expenditures on Which VAT is Pa**										
17											
18	Assumption 1: Technological Import Exemption?										
19	Assumption 2: Year of Registration										
20											
21	Operating Expenditures, Net of VAT										
22	Fixed O&M, Non-Russian, Non-Labor	20,849	21,297	21,744	22,201	22,667	23,143	23,629	24,125	24,632	25,149
23	Variable O&M, Russian, Non-Labor	8,299	8,316	8,320	8,320	8,317	8,309	8,298	8,283	8,263	8,239
24	Fuel Cost	129,359	130,763	132,130	133,454	134,732	135,959	137,133	138,247	139,296	140,277
	Accounting, Legal and Other Costs	935	955	975	996	1,017	1,038	1,060	1,082	1,105	1,128
25	Total, Net of VAT	159,443	161,332	163,169	164,970	166,732	168,450	170,119	171,736	173,296	174,793
26											
27	VAT and Special Tax on Operating Expenditures										
28	Fixed O&M, Non-Russian, Non-Labor	4,483	4,579	4,675	4,773	4,873	4,976	5,080	5,187	5,296	5,407
29	Variable O&M, Russian, Non-Labor	1,784	1,788	1,789	1,789	1,788	1,787	1,784	1,781	1,777	1,771
30	Fuel Cost	27,812	28,114	28,408	28,693	28,967	29,231	29,483	29,723	29,949	30,160
	Accounting, Legal and Other Costs	201	205	210	214	219	223	228	233	237	242
31	Total	34,280	34,686	35,081	35,469	35,847	36,217	36,576	36,923	37,259	37,580
32											
33	VAT Calculations, Inflation Escalated										
34	Russian Equipment	0	0	0	0	0	0	0	0	0	0
35	Russian Material	0	0	0	0	0	0	0	0	0	0
36	Russian Labor	0	0	0	0	0	0	0	0	0	0
37	Russian Indirect	0	0	0	0	0	0	0	0	0	0
38	Non-Russian Equipment	0	0	0	0	0	0	0	0	0	0
39	Non-Russian Indirect	0	0	0	0	0	0	0	0	0	0
	Total Office Equipment	0	0	0	0	0	0	0	0	0	0
	Capital Repairs	2,011	2,053	2,097	2,141	2,185	2,231	2,278	2,326	2,375	2,425
40	Total VAT Calculations on Capital Expenditures	0	0	0	0	0	0	0	0	0	0
41											
42											

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	TAX WORKSHEET VAT and Special Tax	Project Year	1995 0	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11	2007 12	2008 13
43	**VAT/Special Tax Due to Government**															
44																
45	Tax Collected from Customers		0	0	0	592	12,724	38,391	45,698	46,749	47,684	48,685	49,708	50,751	51,817	52,905
46	Tax Expended on Operating Items		0	0	0	1,044	9,117	18,906	21,579	22,195	22,754	23,342	24,135	24,869	25,624	26,400
47	Net Tax Payable After Operations		0	0	0	(453)	3,606	19,485	24,119	24,554	24,930	25,343	25,573	25,883	26,194	26,505
48																
49	Deferred Tax Credit, Beginning Balance		0	0	6,232	32,473	71,951	103,570	99,339	75,220	50,666	25,736	393	0	0	0
50	Tax Expended on Captial Items, Current Period		0	6,232	26,240	39,478	35,225	15,254	0	0	0	0	0	0	0	0
51	Deferred Tax Credit, Available This Period		0	6,232	32,473	71,951	107,176	118,824	99,339	75,220	50,666	25,736	393	0	0	0
52																
53	Tax Due to Government After Credit		0	0	0	0	0	0	0	0	0	0	25,180	25,883	26,194	26,505
54	VAT Recovery		0	0	0	592	12,724	38,391	45,698	46,749	47,684	48,685	25,966	25,883	26,194	26,505
55																
56	Deferred Tax Credit, Ending Balance		0	6,232	32,473	71,951	103,570	99,339	75,220	50,666	25,736	393	0	0	0	0
57																
58	**Revenue Calculations**															
59																
60	Gross Revenues		0	0	0	3,344	71,903	216,955	258,246	264,186	269,469	275,128	280,906	286,805	292,828	298,977
61	VAT/Special Tax Payable to Government		0	0	0	0	0	0	0	0	0	0	25,180	25,883	26,194	26,505
62	Net Revenues		0	0	0	3,344	71,903	216,955	258,246	264,186	269,469	275,128	255,726	260,922	266,634	272,472

TAX WORKSHEET VAT and Special Tax	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27	2023 28	2024 29
43 **VAT/Special Tax Due to Government**																
44																
45 Tax Collected from Customers	54,016	54,324	54,620	54,904	55,177	55,437	55,683	55,915	56,133	56,334	56,520	56,689	56,839	56,971	57,084	57,176
46 Tax Expended on Operating Items	27,199	27,650	28,102	28,556	29,010	29,464	29,918	30,372	30,825	31,276	31,726	32,173	32,602	33,029	33,451	33,868
47 Net Tax Payable After Operations	26,817	26,674	26,517	26,348	26,167	25,972	25,764	25,543	25,308	25,058	24,794	24,516	24,237	23,943	23,633	23,308
48																
49 Deferred Tax Credit, Beginning Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
50 Tax Expended on Captial Items, Current Period	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
51 Deferred Tax Credit, Available This Period	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
52																
53 Tax Due to Government After Credit	26,817	26,674	26,517	26,348	26,167	25,972	25,764	25,543	25,308	25,058	24,794	24,516	24,237	23,943	23,633	23,308
54 VAT Recovery	26,817	26,674	26,517	26,348	26,167	25,972	25,764	25,543	25,308	25,058	24,794	24,516	24,237	23,943	23,633	23,308
55																
56 Deferred Tax Credit, Ending Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
57																
58 **Revenue Calculations**																
59																
60 Gross Revenues	305,256	306,991	308,665	310,273	311,813	313,281	314,673	315,985	317,214	318,355	319,404	320,356	321,208	321,954	322,590	323,111
61 VAT/Special Tax Payable to Government	26,817	26,674	26,517	26,348	26,167	25,972	25,764	25,543	25,308	25,058	24,794	24,516	24,237	23,943	23,633	23,308
62 Net Revenues	278,438	280,317	282,147	283,925	285,646	287,309	288,909	290,442	291,906	293,297	294,609	295,841	296,971	298,012	298,957	299,803

	TAX WORKSHEET VAT and Special Tax	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39
43	**VAT/Special Tax Due to Government**										
44											
45	Tax Collected from Customers	57,247	57,295	57,321	57,322	57,298	57,248	57,170	57,064	56,928	56,761
46	Tax Expended on Operating Items	34,280	34,686	35,081	35,469	35,847	36,217	36,576	36,923	37,259	37,580
47	Net Tax Payable After Operations	22,967	22,609	22,239	21,853	21,451	21,031	20,594	20,140	19,669	19,180
48											
49	Deferred Tax Credit, Beginning Balance	0	0	0	0	0	0	0	0	0	0
50	Tax Expended on Captial Items, Current Period	0	0	0	0	0	0	0	0	0	0
51	Deferred Tax Credit, Available This Period	0	0	0	0	0	0	0	0	0	0
52											
53	Tax Due to Government After Credit	22,967	22,609	22,239	21,853	21,451	21,031	20,594	20,140	19,669	19,180
54	VAT Recovery	22,967	22,609	22,239	21,853	21,451	21,031	20,594	20,140	19,669	19,180
55											
56	Deferred Tax Credit, Ending Balance	0	0	0	0	0	0	0	0	0	0
57											
58	**Revenue Calculations**										
59											
60	Gross Revenues	323,511	323,786	323,929	323,936	323,800	323,515	323,076	322,476	321,708	320,765
61	VAT/Special Tax Payable to Government	22,967	22,609	22,239	21,853	21,451	21,031	20,594	20,140	19,669	19,180
62	Net Revenues	300,544	301,177	301,690	302,082	302,349	302,484	302,482	302,335	302,039	301,585

APPENDIX A.2 -- CAPITAL STRUCTURE SCENARIOS

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SUMMARY OF CAPITAL STRUCTURE SCENARIOS

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9
1 Gross Capacity (MW)	900	900	900	900	900	900	900	900	900
2 Output (GWh/yr), at Busbar	6,209	6,209	6,209	6,209	6,209	6,209	6,209	6,209	6,209
3 Project Cost (including VAT) (million US$)	$764 million	$823 million	$760 million	$798 million	$823 million	$749 million	$783 million	$902 million	$973 million
4 Transmission Line Included?	No	No	No	No	No	No	No	Yes	Yes
Gas Pipeline Included?	No	No	No	No	No	No	No	No	Yes
5 Period of Construction									
Beginning of Simple Cycle	Dec. 1998	Dec. 1998	Dec. 1998	Dec. 1998	Dec. 1998	Dec. 1998	Dec. 1998	Dec. 1998	Dec. 1998
Beginning of Combined Cycle	Dec. 1999	Dec. 1999	Dec. 1999	Dec. 1999	Dec. 1999	Dec. 1999	Dec. 1999	Dec. 1999	Dec. 1999
6 Capital Structure (million US$)									
Debt									
World Bank Loan	$500	$500	$500	$500	$500	$500	$500	$500	$500
ECA Loan	$0	$100	$0	$100	$100	$0	$48	$0	$0
Commercial Bank Loan	$0	$0	$0	$0	$37	$0	$0	$0	$0
Equity									
Russian Investors	$264	$223	$210	$148	$135	$199	$235	$402	$473
Foreign Investors	$0	$0	$50	$50	$50	$50	$0	$0	$0
7 Cost of Capital									
Debt -- Interest Rate									
World Bank Loan	8%	8%	8%	8%	8%	8%	8%	8%	8%
ECA Loan	--	8%	--	8%	8%	--	8%	--	--
Commercial Bank Loan	--	--	--	--	12%	--	--	--	--
Equity -- Rates of Return									
Russian Investors	15%	15%	15%	15%	15%	25%	15%	15%	15%
Foreign Investors	--	--	28%	28%	28%	25%	--	--	--
8 Debt/Equity Ratio	65/35	73/27	66/34	75/25	77/23	66/34	70/30	55/45	51/49
9 Average Tariff (w/o VAT)	$ 0.0302	$ 0.0297	$ 0.0323	$ 0.0323	$ 0.0323	$ 0.0375	$ 0.0299	$ 0.0341	$ 0.0363
Average Tariff (w/ VAT)	$ 0.0366	$ 0.0361	$ 0.0393	$ 0.0392	$ 0.0393	$ 0.0456	$ 0.0364	$ 0.0415	$ 0.0441

PROJECT OVERVIEW

Total Project

Sources of Cash:	Nominal US$ ('000)	% Total
Debt	$500,000	65%
Equity	264,011	35%
Total Capital Investment	$764,011	100%

Equity Returns

Russian Equity Investors	15%
Foreign Equity Investors	#VALUE!

	w/o VAT	w/ VAT
Average Tariff ($/kWh) ('95 US$)	$0.0302	$0.0366

Debt Financing

World Bank Loan	$500,000	100%
Export Credit Agency/Vendor Financing	0	0%
Other Commercial Bank Financing	0	0%
Total Debt Financing	$500,000	100%

Total Project

Uses of Cash:	Nominal US$ ('000)	% Total
Base Project Cost	$419,039	55%
Duties, Excise, VAT, Special Taxes	173,843	23%
Physical Contingencies	66,156	9%
Real Russian vs. US Escalation	51,829	7%
Inflation	46,221	6%
Interest Paid During Construction	0	0%
Capitalized Interest During Const.	77,171	10%
Principal Paid During Construction	0	0%
Working Capital (through 2000)	18,422	2%
Less: Internally-Generated Cash	(88,669)	-12%
Total Project Cost to be Financed Externally	$764,011	100%

Lender Terms

World Bank Loan:
- $500 million draw-down during construction.
- Can be used to finance equipment (which must be procured through international competitive bidding), contingencies, escalation costs, inflation costs, and interest during construction.
- Cannot be used to finance taxes, duties, or equipment which is not procured through international competitive bidding.
- 5 year grace period for repayment of principal and interest.
- 8% interest rate, compounded annually. Actual interest rate may be lower, but lender transaction fees are imbedded in assumed 8% interest rate.
- Interest payable semi-annually.
- 17 year term to maturity.
- Principal amortized, at option of borrower, on straight-line basis in equal semi-annual installments or in equal semi-annual installments of principal and interest.
- Commitment, mobilization and other fees estimated at 2% of principal amount of loan payable at time of closing.
- Other terms and conditions subject to negotiation and may include covenants specifying minimum debt/equity ratio, cash balances, interest coverage ratios, etc. during the loan repayment period.

FINANCIAL STATEMENTS (000 nominal US dollars)	Project Year	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11	2007 12	2008 13
SCENARIO: CASE 1 (Base Case)														
Equity Contributions														
	Percent of Total													
Russian Ownership Group	100%	19,854	63,233	102,193	78,732	0								
Foreign	0%	0	0	0	0	0								
Total Dividends to Investors	100%	19,854	63,233	102,193	78,732	0								
Dividends to Investors														
Russian Ownership Group						12,287	11,403	56,338	58,845	61,296	39,292	41,942	45,023	48,093
Foreign						0	0	0	0	0	0	0	0	0
Total Dividends to Investors						12,287	11,403	56,338	58,845	61,296	39,292	41,942	45,023	48,093
Debt Amortization Schedule														
Beginning Balance		0	31,999	136,473	312,099	463,894	500,000	461,538	423,077	384,615	346,154	307,692	269,231	230,769
Drawdown (inclusive of Capitalized Interest)		31,999	104,474	175,626	151,795	36,106	0	0	0	0	0	0	0	0
Principal Repayment		0	0	0	0	0	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)
Ending Balance		31,999	136,473	312,099	463,894	500,000	461,538	423,077	384,615	346,154	307,692	269,231	230,769	192,308
Interest Accrued		(202)	(3,204)	(11,958)	(25,701)	(36,106)	(40,000)	(36,923)	(33,846)	(30,769)	(27,692)	(24,615)	(21,538)	(18,462)
Interest Paid		0	0	0	0	0	40,000	36,923	33,846	30,769	27,692	24,615	21,538	18,462
Capitalized Interest During Construction (cumulative)		202	3,406	15,364	41,065	77,171								
Project Cash Flows (Straight Line Principal Amortization)														
Revenues (exclusive of VAT)		--	--	2,752	59,179	178,563	212,548	217,437	221,785	226,443	231,198	236,053	241,010	246,072
Total Cash Flows Before Financing		(51,853)	(167,707)	(277,819)	(230,527)	(23,819)	89,865	131,723	131,153	130,527	105,446	105,019	105,023	105,016
New Debt Financing		31,999	104,474	175,626	151,795	36,106	0	0	0	0	0	0	0	0
New Equity Financing		19,854	63,233	102,193	78,732	0	0	0	0	0	0	0	0	0
Interest Paid		0	0	0	0	0	(40,000)	(36,923)	(33,846)	(30,769)	(27,692)	(24,615)	(21,538)	(18,462)
Principal		0	0	0	0	0	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)
Dividends		0	0	0	0	(12,287)	(11,403)	(56,338)	(58,845)	(61,296)	(39,292)	(41,942)	(45,023)	(48,093)

Payback and Return

	Assumed Equity Return	Total Investment	Year to Payback	Cash Dividends (2000-2014)	Cash Dividends Through 2034
Russian Ownership Group	15.0%	$264,011	2006	$758,180	$2,201,970
Foreign	#VALUE!	$0	nm	$0	$0

FINANCIAL STATEMENTS (000 nominal US dollars)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
SCENARIO: CASE 1 (Base Case)															
Equity Contributions															
Russian Ownership Group															
Foreign															
Total Dividends to Investors															
Dividends to Investors															
Russian Ownership Group	51,149	52,632	53,861	55,028	56,130	114,859	93,058	91,957	90,785	89,539	88,218	86,820	85,403	83,905	79,156
Foreign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Dividends to Investors	51,149	52,632	53,861	55,028	56,130	114,859	93,058	91,957	90,785	89,539	88,218	86,820	85,403	83,905	79,156
Debt Amortization Schedule															
Beginning Balance	192,308	153,846	115,385	76,923	38,462	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Principal Repayment	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Ending Balance	153,846	115,385	76,923	38,462	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Interest Accrued	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Interest Paid	15,385	12,308	9,231	6,154	3,077	0	0	0	0	0	0	0	0	0	0
Capitalized Interest During Construction (cumul															
Project Cash Flows (Straight Line Principal ,															
Revenues (exclusive of VAT)	251,239	252,667	254,045	255,369	256,636	257,844	258,990	260,070	261,081	262,020	262,884	263,668	264,369	264,983	265,506
Total Cash Flows Before Financing	104,996	103,401	101,553	99,643	97,669	114,859	93,058	91,957	90,785	89,539	88,218	86,820	85,403	83,905	79,156
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Paid	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Principal	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Dividends	(51,149)	(52,632)	(53,861)	(55,028)	(56,130)	(114,859)	(93,058)	(91,957)	(90,785)	(89,539)	(88,218)	(86,820)	(85,403)	(83,905)	(79,156)
Payback and Return															
Russian Ownership Group															
Foreign															

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FINANCIAL STATEMENTS ('000 nominal US dollars)	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39	Liquidation Value (Working Capital)
SCENARIO: CASE 1 (Base Case)												
Equity Contributions												
Russian Ownership Group												
Foreign												
Total Dividends to Investors												
Dividends to Investors												
Russian Ownership Group	72,660	68,432	65,619	63,379	61,022	58,543	58,659	55,968	53,168	50,259	47,238	18,488
Foreign	0	0	0	0	0	0	0	0	0	0	0	0
Total Dividends to Investors	72,660	68,432	65,619	63,379	61,022	58,543	58,659	55,968	53,168	50,259	47,238	18,488
Debt Amortization Schedule												
Beginning Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0	
Principal Repayment	0	0	0	0	0	0	0	0	0	0	0	
Ending Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
Interest Accrued	0	0	0	0	0	0	0	0	0	0	0	
Interest Paid	0	0	0	0	0	0	0	0	0	0	0	
Capitalized Interest During Construction (cumul												
Project Cash Flows (Straight Line Principal												
Revenues (exclusive of VAT)	265,935	266,264	266,490	266,608	266,614	266,502	266,268	265,906	265,412	264,780	264,004	
Total Cash Flows Before Financing	72,660	68,432	65,619	63,379	61,022	58,543	58,659	55,968	53,168	50,259	47,238	
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0	
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0	
Interest Paid	0	0	0	0	0	0	0	0	0	0	0	
Principal	0	0	0	0	0	0	0	0	0	0	0	
Dividends	(72,660)	(68,432)	(65,619)	(63,379)	(61,022)	(58,543)	(58,659)	(55,968)	(53,168)	(50,259)	(47,238)	
Payback and Return												
Russian Ownership Group												
Foreign												

PROJECT OVERVIEW

Total Project

Sources of Cash:	Nominal US$ ('000)	% Total
Debt	$600,000	73%
Equity	223,264	27%
Total Capital Investment	$823,264	100%

Total Project

Uses of Cash:	Nominal US$ ('000)	% Total
Base Project Cost	$419,039	51%
Duties, Excise, VAT, Special Taxes	173,843	21%
Physical Contingencies	66,156	8%
Real Russian vs. US Escalation	51,829	6%
Inflation	46,221	6%
Interest Paid During Construction	19,634	2%
Capitalized Interest During Const.	72,892	9%
Principal Paid During Construction	33,333	4%
Working Capital (through 2000)	29,981	4%
Less: Internally-Generated Cash	(89,663)	-11%
Total Project Cost to be Financed Externally	$823,264	100%

Equity Returns

Russian Equity Investors	15%
Foreign Equity Investors	#VALUE!

	w/o VAT	w/ VAT
Average Tariff ($/kWh) ('95 US$)	$0.0297	$0.0361

Debt Financing

World Bank Loan	$500,000	83%
Export Credit Agency/Vendor Financing	100,000	17%
Other Commecial Bank Financing	0	0%
Total Debt Financing	$600,000	100%

Lender Terms

World Bank Loan:
- $500 million draw-down during construction.
- Can be used to finance equipment (which must be procured through international competitive bidding), contingencies, escalation costs, inflation costs, and interest during construction.
- Cannot be used to finance taxes, duties, or equipment which is not procured through international competitive bidding.
- 5 year grace period for repayment of principal and interest.
- 8% interest rate, compounded annually. Actual interest rate may be lower, but lender transaction fees are imbedded in assumed 8% interest rate.
- Interest payable semi-annually.
- 17 year term to maturity.
- Principal amortized, at option of borrower, on straight-line basis in equal semi-annual installments or in equal semi-annual installments of principal and interest.
- Commitment, mobilization and other fees estimated at 2% of principal amount of loan payable at time of closing.
- Other terms and conditions subject to negotiation and may include covenants specifying minimum debt/equity ratio, cash balances, interest coverage ratios, etc. during the loan repayment period.

Export Credit Agency/Vendor Financing:
- $100 million line of credit.
- Can be used to finance up to 85% of equipment supplied from home country of export credit agency.
- 3 year grace period for repayment of principal (interest must be paid during construction period).
- 8% interest rate, compounded annually.
- Interest payable semi-annually.
- 8 year term to maturity.
- Principal amortized on straight-line basis in equal semi-annual installments.

FINANCIAL STATEMENTS ('000 nominal US dollars)	Project Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
		1	2	3	4	5	6	7	8	9	10	11	12	13
SCENARIO: CASE 2 ($100 mn ECA Loan)														
Equity Contributions	Percent of Total													
Russian Ownership Group	100%	13,220	42,376	69,544	77,480	20,645 *								
Foreign	0%	0	0	0	0	0								
Total Dividends to Investors	100%	13,220	42,376	69,544	77,480	20,645								
Dividends to Investors														
Russian Ownership Group						0	(0)	35,168	38,490	41,752	48,920	39,152	42,174	45,184
Foreign						0	0	0	0	0	0	0	0	0
Total Dividends to Investors						0	(0)	35,168	38,490	41,752	48,920	39,152	42,174	45,184
Debt Amortization Schedule														
Beginning Balance		0	38,608	164,607	377,320	547,140	566,667	511,538	456,410	401,282	346,154	307,692	269,231	230,769
Drawdown (inclusive of Capitalized Interest)		38,608	125,999	212,713	186,486	36,194	0	0	0	0	0	0	0	0
Principal Repayment		0	0	0	(16,667)	(16,667)	(55,128)	(55,128)	(55,128)	(55,128)	(38,462)	(38,462)	(38,462)	(38,462)
Ending Balance		38,608	164,607	377,320	547,140	566,667	511,538	456,410	401,282	346,154	307,692	269,231	230,769	192,308
Interest Accrued		(177)	(3,872)	(14,454)	(31,163)	(42,860)	(45,333)	(40,923)	(36,513)	(32,103)	(27,692)	(24,615)	(21,538)	(18,462)
Interest Paid		0	1,060	3,907	8,000	6,667	45,333	40,923	36,513	32,103	27,692	24,615	21,538	18,462
Capitalized Interest During Construction (cumulative)		177	2,988	13,535	36,698	72,892								
Project Cash Flows (Straight Line Principal Amortization)														
Revenues (exclusive of VAT)		--	--	2,713	58,350	176,062	209,571	214,391	218,679	223,271	227,959	232,747	237,634	242,625
Total Cash Flows Before Financing		(51,828)	(168,375)	(282,256)	(239,300)	(22,971)	89,927	131,219	130,131	128,983	115,074	102,229	102,174	102,107
New Debt Financing		38,608	125,999	212,713	186,486	36,194	0	0	0	0	0	0	0	0
New Equity Financing		13,220	42,376	69,544	77,480	20,645	0	0	0	0	0	0	0	0
Interest Paid		0	(1,060)	(3,907)	(8,000)	(6,667)	(45,333)	(40,923)	(36,513)	(32,103)	(27,692)	(24,615)	(21,538)	(18,462)
Principal		0	0	0	(16,667)	(16,667)	(55,128)	(55,128)	(55,128)	(55,128)	(38,462)	(38,462)	(38,462)	(38,462)
Dividends		0	0	0	0	0	0	(35,168)	(38,490)	(41,752)	(48,920)	(39,152)	(42,174)	(45,184)

Payback and Return

	Assumed Equity Return	Total Investment	Year to Payback	Cash Dividends (2000-2014)	Cash Dividends Through 2034
Russian Ownership Group	15.0%	$223,264	2007	$656,423	$2,037,619
Foreign	#VALUE!	$0	nm	$0	$0

* Equity contriibutions required in year 2000 to satisfy cash flow requirements associated with principal repayment terms of ECA loan.

FINANCIAL STATEMENTS ('000 nominal US dollars)	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27	2023 28
SCENARIO: CASE 2 ($100 mn ECA Loan)															
Equity Contributions															
Russian Ownership Group															
Foreign															
Total Dividends to Investors															
Dividends to Investors															
Russian Ownership Group	48,179	49,642	50,855	52,006	53,094	111,808	89,994	88,880	87,695	86,438	85,107	83,699	82,274	80,769	76,014
Foreign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Dividends to Investors	48,179	49,642	50,855	52,006	53,094	111,808	89,994	88,880	87,695	86,438	85,107	83,699	82,274	80,769	76,014
Debt Amortization Schedule															
Beginning Balance	192,308	153,846	115,385	76,923	38,462	0	0	0	0	0	0	0	0	0	0
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Principal Repayment	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Ending Balance	153,846	115,385	76,923	38,462	0	0	0	0	0	0	0	0	0	0	0
Interest Accrued	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Interest Paid	15,385	12,308	9,231	6,154	3,077	0	0	0	0	0	0	0	0	0	0
Capitalized Interest During Construction (cumul															
Project Cash Flows (Straight Line Principal,															
Revenues (exclusive of VAT)	247,720	249,128	250,486	251,792	253,041	254,233	255,362	256,427	257,424	258,350	259,201	259,974	260,665	261,271	261,787
Total Cash Flows Before Financing	102,025	100,411	98,547	96,621	94,632	111,808	89,994	88,880	87,695	86,438	85,107	83,699	82,274	80,769	76,014
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Paid	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Principal	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Dividends	(48,179)	(49,642)	(50,855)	(52,006)	(53,094)	(111,808)	(89,994)	(88,880)	(87,695)	(86,438)	(85,107)	(83,699)	(82,274)	(80,769)	(76,014)
Payback and Return															
Russian Ownership Group															
Foreign															

* Equity contriibutions required in year 2000 to

FINANCIAL STATEMENTS ('000 nominal US dollars)	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39	Liquidation Value (Working Capital)
SCENARIO: CASE 2 ($100 mn ECA Loan)												
Equity Contributions												
Russian Ownership Group												
Foreign												
Total Dividends to Investors												
Dividends to Investors												
Russian Ownership Group	69,513	65,280	62,465	60,224	57,866	55,389	55,508	52,820	50,026	47,125	44,113	18,299
Foreign	0	0	0	0	0	0	0	0	0	0	0	0
Total Dividends to Investors	69,513	65,280	62,465	60,224	57,866	55,389	55,508	52,820	50,026	47,125	44,113	18,299
Debt Amortization Schedule												
Beginning Balance	0	0	0	0	0	0	0	0	0	0	0	
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0	
Principal Repayment	0	0	0	0	0	0	0	0	0	0	0	
Ending Balance	0	0	0	0	0	0	0	0	0	0	0	
Interest Accrued	0	0	0	0	0	0	0	0	0	0	0	
Interest Paid	0	0	0	0	0	0	0	0	0	0	0	
Capitalized Interest During Construction (cumul												
Project Cash Flows (Straight Line Principal												
Revenues (exclusive of VAT)	262,210	262,534	262,757	262,874	262,879	262,769	262,538	262,181	261,694	261,071	260,306	
Total Cash Flows Before Financing	69,513	65,280	62,465	60,224	57,866	55,389	55,508	52,820	50,026	47,125	44,113	
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0	
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0	
Interest Paid	0	0	0	0	0	0	0	0	0	0	0	
Principal	0	0	0	0	0	0	0	0	0	0	0	
Dividends	(69,513)	(65,280)	(62,465)	(60,224)	(57,866)	(55,389)	(55,508)	(52,820)	(50,026)	(47,125)	(44,113)	
Payback and Return												
Russian Ownership Group												
Foreign												

* Equity contriibutions required in year 2000 to

PROJECT OVERVIEW

0

Total Project

Sources of Cash:	Nominal US$ ('000)	% Total
Debt	$500,000	66%
Equity	260,079	34%
Total Capital Investment	$760,079	100%

Equity Returns

Russian Equity Investors	15%
Foreign Equity Investors	28%

	w/o VAT	w/ VAT
Average Tariff ($/kWh) ('95 US$)	$0.0323	$0.0393

Debt Financing

World Bank Loan	$500,000	100%
Export Credit Agency/Vendor Financing	0	0%
Other Commecial Bank Financing	0	0%
Total Debt Financing	$500,000	100%

Total Project

Uses of Cash:	Nominal US$ ('000)	% Total
Base Project Cost	$419,039	55%
Duties, Excise, VAT, Special Taxes	173,843	23%
Physical Contingencies	66,156	9%
Real Russian vs. US Escalation	51,829	7%
Inflation	46,221	6%
Interest Paid During Construction	0	0%
Capitalized Interest During Const.	77,382	10%
Principal Paid During Construction	0	0%
Working Capital (through 2000)	18,969	2%
Less: Internally-Generated Cash	(93,360)	-12%
Total Project Cost to be Financed Externally	$760,079	100%

Lender Terms

World Bank Loan:
- $500 million draw-down during construction.
- Can be used to finance equipment (which must be procured through international competitive bidding), contingencies, escalation costs, inflation costs, and interest during construction.
- Cannot be used to finance taxes, duties, or equipment which is not procured through international competitive bidding.
- 5 year grace period for repayment of principal and interest.
- 8% interest rate, compounded annually. Actual interest rate may be lower, but lender transaction fees are imbedded in assumed 8% interest rate.
- Interest payable semi-annually.
- 17 year term to maturity.
- Principal amortized, at option of borrower, on straight-line basis in equal semi-annual installments or in equal semi-annual installments of principal and interest.
- Commitment, mobilization and other fees estimated at 2% of principal amount of loan payable at time of closing.
- Other terms and conditions subject to negotiation and may include covenants specifying minimum debt/equity ratio, cash balances, interest coverage ratios, etc. during the loan repayment period.

FINANCIAL STATEMENTS ('000 nominal US dollars)	Project Year	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11	2007 12	2008 13
SCENARIO: CASE 3 ($50 mn Foreign Equity)														
Equity Contributions	Percent of Total													
Russian Ownership Group	81%	15,894	50,621	81,828	61,736	0								
Foreign	19%	3,783	12,048	19,476	14,694	0								
Total Dividends to Investors	100%	19,677	62,669	101,303	76,430	0								
Dividends to Investors														
Russian Ownership Group						14,343	15,321	43,394	45,126	39,810	33,010	35,095	37,208	39,317
Foreign						8,600	9,187	26,019	27,057	23,870	19,793	21,043	22,309	23,574
Total Dividends to Investors						22,943	24,508	69,413	72,184	63,680	52,803	56,138	59,517	62,891
Debt Amortization Schedule														
Beginning Balance		0	32,177	137,233	313,872	463,897	500,000	461,538	423,077	384,615	346,154	307,692	269,231	230,769
Drawdown (inclusive of Capitalized Interest)		32,177	105,056	176,639	150,026	36,102	0	0	0	0	0	0	0	0
Principal Repayment		0	0	0	0	0	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)
Ending Balance		32,177	137,233	313,872	463,897	500,000	461,538	423,077	384,615	346,154	307,692	269,231	230,769	192,308
Interest Accrued		(203)	(3,221)	(12,025)	(25,830)	(36,102)	(40,000)	(36,923)	(33,846)	(30,769)	(27,692)	(24,615)	(21,538)	(18,462)
Interest Paid		0	0	0	0	0	40,000	36,923	33,846	30,769	27,692	24,615	21,538	18,462
Capitalized Interest During Construction (cumulative)		203	3,425	15,450	41,280	$\boxed{77,382}$								
Project Cash Flows (Straight Line Principal Amortization)														
Revenues (exclusive of VAT)		--	--	2,948	63,396	191,287	227,694	232,931	237,589	242,579	247,673	252,874	258,184	263,606
Total Cash Flows Before Financing		(51,854)	(167,725)	(277,944)	(225,919)	(13,159)	102,434	144,798	144,491	132,910	118,956	119,215	119,517	119,814
New Debt Financing		32,177	105,056	176,639	150,026	36,102	0	0	0	0	0	0	0	0
New Equity Financing		19,677	62,669	101,303	76,430	0	0	0	0	0	0	0	0	0
Interest Paid		0	0	0	0	0	(40,000)	(36,923)	(33,846)	(30,769)	(27,692)	(24,615)	(21,538)	(18,462)
Principal		0	0	0	0	0	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)
Dividends		0	0	0	0	(22,943)	(24,508)	(69,413)	(72,184)	(63,680)	(52,803)	(56,138)	(59,517)	(62,891)

Payback and Return

	Assumed Equity Return	Total Investment	Year to Payback	Cash Dividends (2000-2014)	Cash Dividends Through 2034
Russian Ownership Group	15.0%	$210,079	2006	$599,957	$1,701,608
Foreign	28.0%	$50,000	2003	$359,729	$1,020,270

FINANCIAL STATEMENTS ('000 nominal US dollars)	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27	2023 28
SCENARIO: CASE 3 ($50 mn Foreign Equit															
Equity Contributions															
Russian Ownership Group															
Foreign															
Total Dividends to Investors															
Dividends to Investors															
Russian Ownership Group	41,422	42,411	43,232	44,011	44,748	81,508	67,923	67,275	66,580	65,837	65,044	64,199	63,340	62,427	59,478
Foreign	24,836	25,429	25,921	26,389	26,831	48,872	40,726	40,338	39,921	39,475	39,000	38,494	37,978	37,431	35,663
Total Dividends to Investors	66,258	67,840	69,153	70,400	71,579	130,380	108,649	107,613	106,501	105,312	104,043	102,693	101,319	99,858	95,141
Debt Amortization Schedule															
Beginning Balance	192,308	153,846	115,385	76,923	38,462	0	0	0	0	0	0	0	0	0	0
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Principal Repayment	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Ending Balance	153,846	115,385	76,923	38,462	0	0	0	0	0	0	0	0	0	0	0
Interest Accrued	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Interest Paid	15,385	12,308	9,231	6,154	3,077	0	0	0	0	0	0	0	0	0	0
Capitalized Interest During Construction (cumul															
Project Cash Flows (Straight Line Principal															
Revenues (exclusive of VAT)	269,142	270,672	272,148	273,566	274,924	276,218	277,445	278,602	279,685	280,691	281,616	282,456	283,207	283,865	284,426
Total Cash Flows Before Financing	120,105	118,609	116,845	115,015	113,117	130,380	108,649	107,613	106,501	105,312	104,043	102,693	101,319	99,858	95,141
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Paid	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Principal	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Dividends	(66,258)	(67,840)	(69,153)	(70,400)	(71,579)	(130,380)	(108,649)	(107,613)	(106,501)	(105,312)	(104,043)	(102,693)	(101,319)	(99,858)	(95,141)
Payback and Return															
Russian Ownership Group															
Foreign															

FINANCIAL STATEMENTS (000 nominal US dollars)	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39	Liquidation Value (Working Capital)
SCENARIO: CASE 3 ($50 mn Foreign Equit												
Equity Contributions												
Russian Ownership Group												
Foreign												
Total Dividends to Investors												
Dividends to Investors												
Russian Ownership Group	55,434	52,803	51,053	49,658	48,185	46,631	46,695	44,999	43,230	41,388	39,471	6,935
Foreign	33,238	31,660	30,611	29,774	28,891	27,960	27,998	26,981	25,921	24,816	23,667	4,158
Total Dividends to Investors	88,672	84,463	81,664	79,432	77,076	74,590	74,693	71,980	69,151	66,205	63,138	11,093
Debt Amortization Schedule												
Beginning Balance	0	0	0	0	0	0	0	0	0	0	0	
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0	
Principal Repayment	0	0	0	0	0	0	0	0	0	0	0	
Ending Balance	0	0	0	0	0	0	0	0	0	0	0	
Interest Accrued	0	0	0	0	0	0	0	0	0	0	0	
Interest Paid	0	0	0	0	0	0	0	0	0	0	0	
Capitalized Interest During Construction (cumul												
Project Cash Flows (Straight Line Principal												
Revenues (exclusive of VAT)	284,885	285,238	285,480	285,606	285,612	285,492	285,241	284,854	284,325	283,648	282,817	
Total Cash Flows Before Financing	88,672	84,463	81,664	79,432	77,076	74,590	74,693	71,980	69,151	66,205	63,138	
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0	
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0	
Interest Paid	0	0	0	0	0	0	0	0	0	0	0	
Principal	0	0	0	0	0	0	0	0	0	0	0	
Dividends	(88,672)	(84,463)	(81,664)	(79,432)	(77,076)	(74,590)	(74,693)	(71,980)	(69,151)	(66,205)	(63,138)	
Payback and Return												
Russian Ownership Group												
Foreign												

PROJECT OVERVIEW

Total Project

Sources of Cash:	Nominal US$ ('000)	% Total
Debt	$500,000	66%
Equity	260,079	34%
Total Capital Investment	$760,079	100%

Total Project

Uses of Cash:	Nominal US$ ('000)	% Total
Base Project Cost	$419,039	55%
Duties, Excise, VAT, Special Taxes	173,843	23%
Physical Contingencies	66,156	9%
Real Russian vs. US Escalation	51,829	7%
Inflation	46,221	6%
Interest Paid During Construction	0	0%
Capitalized Interest During Const.	77,382	10%
Principal Paid During Construction	0	0%
Working Capital (through 2000)	18,969	2%
Less: Internally-Generated Cash	(93,360)	-12%
Total Project Cost to be Financed Externally	$760,079	100%

Equity Returns

Russian Equity Investors	15%
Foreign Equity Investors	28%

	w/o VAT	w/ VAT
Average Tariff ($/kWh) ('95 US$)	$0.0323	$0.0393

Debt Financing

World Bank Loan	$500,000	100%
Export Credit Agency/Vendor Financing	0	0%
Other Commecial Bank Financing	0	0%
Total Debt Financing	$500,000	100%

Scenario: Case 3
($50 mn Foreign Equity)

Lender Terms

World Bank Loan:

- $500 million draw-down during construction.
- Can be used to finance equipment (which must be procured through international competitive bidding), contingencies, escalation costs, inflation costs, and interest during construction.
- Cannot be used to finance taxes, duties, or equipment which is not procured through international competitive bidding.
- 5 year grace period for repayment of principal and interest.
- 8% interest rate, compounded annually. Actual interest rate may be lower, but lender transaction fees are imbedded in assumed 8% interest rate.
- Interest payable semi-annually.
- 17 year term to maturity.
- Principal amortized, at option of borrower, on straight-line basis in equal semi-annual installments or in equal semi-annual installments of principal and interest.
- Commitment, mobilization and other fees estimated at 2% of principal amount of loan payable at time of closing.
- Other terms and conditions subject to negotiation and may include covenants specifying minimum debt/equity ratio, cash balances, interest coverage ratios, etc. during the loan repayment period.

FINANCIAL STATEMENTS (000 nominal US dollars)	Project Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
		1	2	3	4	5	6	7	8	9	10	11	12	13
SCENARIO: CASE 3 ($50 mn Foreign Equity)														
Equity Contributions	Percent of Total													
Russian Ownership Group	81%	15,894	50,621	81,828	61,736	0								
Foreign	19%	3,783	12,048	19,476	14,694	0								
Total Dividends to Investors	100%	19,677	62,669	101,303	76,430	0								
Dividends to Investors														
Russian Ownership Group						14,343	15,321	43,394	45,126	39,810	33,010	35,095	37,208	39,317
Foreign						8,600	9,187	26,019	27,057	23,870	19,793	21,043	22,309	23,574
Total Dividends to Investors						22,943	24,508	69,413	72,184	63,680	52,803	56,138	59,517	62,891
Debt Amortization Schedule														
Beginning Balance		0	32,177	137,233	313,872	463,897	500,000	461,538	423,077	384,615	346,154	307,692	269,231	230,769
Drawdown (inclusive of Capitalized Interest)		32,177	105,056	176,639	150,026	36,102	0	0	0	0	0	0	0	0
Principal Repayment		0	0	0	0	0	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)
Ending Balance		32,177	137,233	313,872	463,897	500,000	461,538	423,077	384,615	346,154	307,692	269,231	230,769	192,308
Interest Accrued		(203)	(3,221)	(12,025)	(25,830)	(36,102)	(40,000)	(36,923)	(33,846)	(30,769)	(27,692)	(24,615)	(21,538)	(18,462)
Interest Paid		0	0	0	0	0	40,000	36,923	33,846	30,769	27,692	24,615	21,538	18,462
Capitalized Interest During Construction (cumulative)		203	3,425	15,450	41,280	$\boxed{77,382}$								
Project Cash Flows (Straight Line Principal Amortization)														
Revenues (exclusive of VAT)		--	--	2,948	63,396	191,287	227,694	232,931	237,589	242,579	247,673	252,874	258,184	263,606
Total Cash Flows Before Financing		(51,854)	(167,725)	(277,944)	(225,919)	(13,159)	102,434	144,798	144,491	132,910	118,956	119,215	119,517	119,814
New Debt Financing		32,177	105,056	176,639	150,026	36,102	0	0	0	0	0	0	0	0
New Equity Financing		19,677	62,669	101,303	76,430	0	0	0	0	0	0	0	0	0
Interest Paid		0	0	0	0	0	(40,000)	(36,923)	(33,846)	(30,769)	(27,692)	(24,615)	(21,538)	(18,462)
Principal		0	0	0	0	0	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)
Dividends		0	0	0	0	(22,943)	(24,508)	(69,413)	(72,184)	(63,680)	(52,803)	(56,138)	(59,517)	(62,891)

Payback and Return

	Assumed Equity Return	Total Investment	Year to Payback	Cash Dividends (2000-2014)	Cash Dividends Through 2034
Russian Ownership Group	15.0%	$210,079	2006	$599,957	$1,701,608
Foreign	28.0%	$50,000	2003	$359,729	$1,020,270

FINANCIAL STATEMENTS ('000 nominal US dollars)	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27	2023 28
SCENARIO: CASE 3 ($50 mn Foreign Equit															
Equity Contributions															
Russian Ownership Group															
Foreign															
Total Dividends to Investors															
Dividends to Investors															
Russian Ownership Group	41,422	42,411	43,232	44,011	44,748	81,508	67,923	67,275	66,580	65,837	65,044	64,199	63,340	62,427	59,478
Foreign	24,836	25,429	25,921	26,389	26,831	48,872	40,726	40,338	39,921	39,475	39,000	38,494	37,978	37,431	35,663
Total Dividends to Investors	66,258	67,840	69,153	70,400	71,579	130,380	108,649	107,613	106,501	105,312	104,043	102,693	101,319	99,858	95,141
Debt Amortization Schedule															
Beginning Balance	192,308	153,846	115,385	76,923	38,462	0	0	0	0	0	0	0	0	0	0
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Principal Repayment	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Ending Balance	153,846	115,385	76,923	38,462	0	0	0	0	0	0	0	0	0	0	0
Interest Accrued	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Interest Paid	15,385	12,308	9,231	6,154	3,077	0	0	0	0	0	0	0	0	0	0
Capitalized Interest During Construction (cumul															
Project Cash Flows (Straight Line Principal ,															
Revenues (exclusive of VAT)	269,142	270,672	272,148	273,566	274,924	276,218	277,445	278,602	279,685	280,691	281,616	282,456	283,207	283,865	284,426
Total Cash Flows Before Financing	120,105	118,609	116,845	115,015	113,117	130,380	108,649	107,613	106,501	105,312	104,043	102,693	101,319	99,858	95,141
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Paid	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Principal	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Dividends	(66,258)	(67,840)	(69,153)	(70,400)	(71,579)	(130,380)	(108,649)	(107,613)	(106,501)	(105,312)	(104,043)	(102,693)	(101,319)	(99,858)	(95,141)
Payback and Return															
Russian Ownership Group															
Foreign															

FINANCIAL STATEMENTS ('000 nominal US dollars)	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39	
SCENARIO: CASE 3 ($50 mn Foreign Equit												
Equity Contributions												
Russian Ownership Group												
Foreign												
Total Dividends to Investors												
Dividends to Investors												Liquidation Value (Working Capital)
Russian Ownership Group	55,434	52,803	51,053	49,658	48,185	46,631	46,695	44,999	43,230	41,388	39,471	6,935
Foreign	33,238	31,660	30,611	29,774	28,891	27,960	27,998	26,981	25,921	24,816	23,667	4,158
Total Dividends to Investors	88,672	84,463	81,664	79,432	77,076	74,590	74,693	71,980	69,151	66,205	63,138	11,093
Debt Amortization Schedule												
Beginning Balance	0	0	0	0	0	0	0	0	0	0	0	
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0	
Principal Repayment	0	0	0	0	0	0	0	0	0	0	0	
Ending Balance	0	0	0	0	0	0	0	0	0	0	0	
Interest Accrued	0	0	0	0	0	0	0	0	0	0	0	
Interest Paid	0	0	0	0	0	0	0	0	0	0	0	
Capitalized Interest During Construction (cumul												
Project Cash Flows (Straight Line Principal												
Revenues (exclusive of VAT)	284,885	285,238	285,480	285,606	285,612	285,492	285,241	284,854	284,325	283,648	282,817	
Total Cash Flows Before Financing	88,672	84,463	81,664	79,432	77,076	74,590	74,693	71,980	69,151	66,205	63,138	
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0	
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0	
Interest Paid	0	0	0	0	0	0	0	0	0	0	0	
Principal	0	0	0	0	0	0	0	0	0	0	0	
Dividends	(88,672)	(84,463)	(81,664)	(79,432)	(77,076)	(74,590)	(74,693)	(71,980)	(69,151)	(66,205)	(63,138)	
Payback and Return												
Russian Ownership Group												
Foreign												

PROJECT OVERVIEW

Total Project

Sources of Cash:	Nominal US$ ('000)	% Total
Debt	$637,320	77%
Equity	185,414	23%
Total Capital Investment	$822,734	100%

Equity Returns

Russian Equity Investors	15%
Foreign Equity Investors	28%

	w/o VAT	w/ VAT
Average Tariff ($/kWh) ('95 US$)	$0.0323	$0.0393

Debt Financing

World Bank Loan	$500,000	78%
Export Credit Agency/Vendor Financing	137,320	22%
Other Commecial Bank Financing	0	0%
Total Debt Financing	$637,320	100%

Total Project

Uses of Cash:	Nominal US$ ('000)	% Total
Base Project Cost	$419,039	51%
Duties, Excise, VAT, Special Taxes	173,843	21%
Physical Contingencies	66,156	8%
Real Russian vs. US Escalation	51,829	6%
Inflation	46,221	6%
Interest Paid During Construction	30,630	4%
Capitalized Interest During Const.	71,304	9%
Principal Paid During Construction	45,773	6%
Working Capital (through 2000)	35,628	4%
Less: Internally-Generated Cash	(117,689)	-14%
Total Project Cost to be Financed Externally	$822,734	100%

Scenario: Case 5
(80/20 Debt/Equity Ratio, $100 mn ECA Loan, $37 mn Commercial Bank Loan, $50 mn Foreign Equity)

Lender Terms

World Bank Loan:
- $500 million draw-down during construction.
- Can be used to finance equipment (which must be procured through international competitive bidding), contingencies, escalation costs, inflation costs, and interest during construction.
- Cannot be used to finance taxes, duties, or equipment which is not procured through international competitive bidding.
- 5 year grace period for repayment of principal and interest.
- 8% interest rate, compounded annually. Actual interest rate may be lower, but lender transaction fees are imbedded in assumed 8% interest rate.
- Interest payable semi-annually.
- 17 year term to maturity.
- Principal amortized, at option of borrower, on straight-line basis in equal semi-annual installments or in equal semi-annual installments of principal and interest.
- Commitment, mobilization and other fees estimated at 2% of principal amount of loan payable at time of closing.
- Other terms and conditions subject to negotiation and may include covenants specifying minimum debt/equity ratio, cash balances, interest coverage ratios, etc. during the loan repayment period.

Export Credit Agency/Vendor Financing:
- $100 million line of credit.
- Can be used to finance up to 85% of equipment supplied from home country of export credit agency.
- 3 year grace period for repayment of principal (interest must be paid during construction period).
- 8% interest rate, compounded annually.
- Interest payable semi-annually.
- 8 year term to maturity.
- Principal amortized on straight-line basis in equal semi-annual installments.

Other Commercial Bank Financing:
- This loan is shown for illustration purposes only. It is highly unlikely that such a high level of debt financing could be arranged for this project.
- This assumed loan is input at 12% interest rate, 8 year term to maturity.

FINANCIAL STATEMENTS ('000 nominal US dollars)	Project Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
		1	2	3	4	5	6	7	8	9	10	11	12	13

SCENARIO: CASE 5 (80/20 Debt Equity Ratio, $100 mn ECA Loan, $37 mn Commercial Bank Loan, $50 mn Foreign Equity)

		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Equity Contributions														
	Percent of Total													
Russian Ownership Group	73%	7,948	25,566	42,320	53,338	6,242 *								
Foreign	27%	2,935	9,440	15,626	19,694	2,305								
Total Dividends to Investors	100%	10,882	35,005	57,947	73,032	8,547								
Dividends to Investors														
Russian Ownership Group						0	(0)	20,946	22,924	19,397	31,389	27,007	28,628	30,247
Foreign						0	(0)	22,768	24,918	21,084	34,119	29,356	31,118	32,878
Total Dividends to Investors						0	(0)	43,713	47,842	40,480	65,508	56,363	59,747	63,125
Debt Amortization Schedule														
Beginning Balance		0	40,936	174,741	401,846	578,207	591,547	530,199	468,850	407,502	346,154	307,692	269,231	230,769
Drawdown (inclusive of Capitalized Interest)		40,936	133,805	227,105	199,248	38,227	0	0	0	0	0	0	0	0
Principal Repayment		0	0	0	(22,887)	(22,887)	(61,348)	(61,348)	(61,348)	(61,348)	(38,462)	(38,462)	(38,462)	(38,462)
Ending Balance		40,936	174,741	401,846	578,207	591,547	530,199	468,850	407,502	346,154	307,692	269,231	230,769	192,308
Interest Accrued		(168)	(4,307)	(16,094)	(34,726)	(46,640)	(48,331)	(43,171)	(38,012)	(32,852)	(27,692)	(24,615)	(21,538)	(18,462)
Interest Paid		0	1,644	6,077	12,496	10,413	48,331	43,171	38,012	32,852	27,692	24,615	21,538	18,462
Capitalized Interest During Construction (cumulative)		168	2,831	12,848	35,078	71,304								
Project Cash Flows (Straight Line Principal Amortization)														
Revenues (exclusive of VAT)		--	--	2,951	63,463	191,489	227,934	233,176	237,840	242,834	247,934	253,140	258,456	263,884
Total Cash Flows Before Financing		(51,818)	(168,811)	(285,051)	(236,897)	(8,385)	106,590	148,233	147,202	134,681	131,661	119,440	119,747	120,048
New Debt Financing		40,936	133,805	227,105	199,248	38,227	0	0	0	0	0	0	0	0
New Equity Financing		10,882	35,005	57,947	73,032	8,547	0	0	0	0	0	0	0	0
Interest Paid		0	(1,644)	(6,077)	(12,496)	(10,413)	(48,331)	(43,171)	(38,012)	(32,852)	(27,692)	(24,615)	(21,538)	(18,462)
Principal		0	0	0	(22,887)	(22,887)	(61,348)	(61,348)	(61,348)	(61,348)	(38,462)	(38,462)	(38,462)	(38,462)
Dividends		0	0	0	0	0	0	(43,713)	(47,842)	(40,480)	(65,508)	(56,363)	(59,747)	(63,125)

Payback and Return

	Assumed Equity Return	Total Investment	Year to Payback	Cash Dividends (2000-2014)	Cash Dividends Through 2034
Russian Ownership Group	15.0%	$135,414	2007	$409,128	$1,255,916
Foreign	28.0%	$50,000	2004	$444,716	$1,365,163

* Equity contributions required in year 2000 to satisfy cash flow requirements associated with principal repayment terms of ECA loan and commercial bank loan.

FINANCIAL STATEMENTS ('000 nominal US dollars)	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27	2023 28
SCENARIO: CASE 5 (80/20 Debt Equity Rati															
Equity Contributions															
Russian Ownership Group															
Foreign															
Total Dividends to Investors															
Dividends to Investors															
Russian Ownership Group	31,863	32,622	33,251	33,849	34,415	62,591	52,178	51,683	51,150	50,581	49,974	49,327	48,669	47,969	45,709
Foreign	34,635	35,459	36,144	36,794	37,408	68,035	56,717	56,178	55,600	54,981	54,321	53,618	52,902	52,142	49,685
Total Dividends to Investors	66,498	68,081	69,395	70,643	71,823	130,626	108,896	107,861	106,750	105,562	104,294	102,944	101,571	100,111	95,394
Debt Amortization Schedule															
Beginning Balance	192,308	153,846	115,385	76,923	38,462	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Principal Repayment	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Ending Balance	153,846	115,385	76,923	38,462	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Interest Accrued	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Interest Paid	15,385	12,308	9,231	6,154	3,077	0	0	0	0	0	0	0	0	0	0
Capitalized Interest During Construction (cumul															
Project Cash Flows (Straight Line Principal															
Revenues (exclusive of VAT)	269,425	270,957	272,434	273,854	275,213	276,509	277,737	278,896	279,980	280,987	281,913	282,754	283,505	284,164	284,725
Total Cash Flows Before Financing	120,344	118,850	117,087	115,258	113,362	130,626	108,896	107,861	106,750	105,562	104,294	102,944	101,571	100,111	95,394
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Paid	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Principal	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Dividends	(66,498)	(68,081)	(69,395)	(70,643)	(71,823)	(130,626)	(108,896)	(107,861)	(106,750)	(105,562)	(104,294)	(102,944)	(101,571)	(100,111)	(95,394)
Payback and Return															
Russian Ownership Group															
Foreign															

* Equity contributions required in year 2000 to s

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FINANCIAL STATEMENTS ('000 nominal US dollars)	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39	Liquidation Value (Working Capital)
SCENARIO: CASE 5 (80/20 Debt Equity Rati												
Equity Contributions												
Russian Ownership Group												
Foreign												
Total Dividends to Investors												
Dividends to Investors												
Russian Ownership Group	42,609	40,593	39,252	38,182	37,053	35,862	35,912	34,611	33,256	31,844	30,374	5,315
Foreign	46,316	44,124	42,666	41,504	40,277	38,982	39,035	37,622	36,149	34,614	33,016	5,778
Total Dividends to Investors	88,925	84,717	81,918	79,686	77,330	74,845	74,947	72,233	69,404	66,457	63,389	11,093
Debt Amortization Schedule												
Beginning Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0	
Principal Repayment	0	0	0	0	0	0	0	0	0	0	0	
Ending Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
Interest Accrued	0	0	0	0	0	0	0	0	0	0	0	
Interest Paid	0	0	0	0	0	0	0	0	0	0	0	
Capitalized Interest During Construction (cumul												
Project Cash Flows (Straight Line Principal												
Revenues (exclusive of VAT)	285,185	285,538	285,780	285,907	285,913	285,793	285,542	285,154	284,624	283,946	283,114	
Total Cash Flows Before Financing	88,925	84,717	81,918	79,686	77,330	74,845	74,947	72,233	69,404	66,457	63,389	
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0	
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0	
Interest Paid	0	0	0	0	0	0	0	0	0	0	0	
Principal	0	0	0	0	0	0	0	0	0	0	0	
Dividends	(88,925)	(84,717)	(81,918)	(79,686)	(77,330)	(74,845)	(74,947)	(72,233)	(69,404)	(66,457)	(63,389)	
Payback and Return												
Russian Ownership Group												
Foreign												

* Equity contributions required in year 2000 to s

PROJECT OVERVIEW

0

Total Project

Sources of Cash:	Nominal US$ ('000)	% Total
Debt	$500,000	67%
Equity	249,264	33%
Total Capital Investment	$749,264	100%

Equity Returns

Russian Equity Investors	25%
Foreign Equity Investors	25%

	w/o VAT	w/ VAT
Average Tariff ($/kWh) ('95 US$)	$0.0375	$0.0456

Debt Financing

World Bank Loan	$500,000	100%
Export Credit Agency/Vendor Financing	0	0%
Other Commecial Bank Financing	0	0%
Total Debt Financing	$500,000	100%

Total Project

Uses of Cash:	Nominal US$ ('000)	% Total
Base Project Cost	$419,039	56%
Duties, Excise, VAT, Special Taxes	173,843	23%
Physical Contingencies	66,156	9%
Real Russian vs. US Escalation	51,829	7%
Inflation	46,221	6%
Interest Paid During Construction	0	0%
Capitalized Interest During Const.	77,976	10%
Principal Paid During Construction	0	0%
Working Capital (through 2000)	20,291	3%
Less: Internally-Generated Cash	(106,091)	-14%
Total Project Cost to be Financed Externally	$749,264	100%

Scenario: Case 6
(25% Returns for Russian and Foreign Equity,
$50 mn Foreign Equity)

Lender Terms

World Bank Loan:
- $500 million draw-down during construction.
- Can be used to finance equipment (which must be procured through international competitive bidding), contingencies, escalation costs, inflation costs, and interest during construction.
- Cannot be used to finance taxes, duties, or equipment which is not procured through international competitive bidding.
- 5 year grace period for repayment of principal and interest.
- 8% interest rate, compounded annually. Actual interest rate may be lower, but lender transaction fees are imbedded in assumed 8% interest rate.
- Interest payable semi-annually.
- 17 year term to maturity.
- Principal amortized, at option of borrower, on straight-line basis in equal semi-annual installments or in equal semi-annual installments of principal and interest.
- Commitment, mobilization and other fees estimated at 2% of principal amount of loan payable at time of closing.
- Other terms and conditions subject to negotiation and may include covenants specifying minimum debt/equity ratio, cash balances, interest coverage ratios, etc. during the loan repayment period.

FINANCIAL STATEMENTS ('000 nominal US dollars)	Project Year	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11	2007 12	2008 13
SCENARIO: CASE 6 (25% Returns for Russian and Foreign Equity,$50 mn Foreign Equity)														
Equity Contributions	Percent of Total													
Russian Ownership Group	80%	15,332	48,831	78,985	56,116	0								
Foreign	20%	3,847	12,253	19,819	14,081	0								
Total Dividends to Investors	100%	19,179	61,084	98,804	70,197	0								
Dividends to Investors														
Russian Ownership Group						38,936	43,749	80,732	77,842	67,518	69,054	72,284	75,561	78,846
Foreign						9,770	10,978	20,258	19,532	16,942	17,327	18,138	18,960	19,784
Total Dividends to Investors						48,706	54,726	100,990	97,374	84,460	86,382	90,422	94,521	98,630
Debt Amortization Schedule														
Beginning Balance		0	32,678	139,369	318,865	463,909	500,000	461,538	423,077	384,615	346,154	307,692	269,231	230,769
Drawdown (inclusive of Capitalized Interest)		32,678	106,691	179,496	145,044	36,091	0	0	0	0	0	0	0	0
Principal Repayment		0	0	0	0	0	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)
Ending Balance		32,678	139,369	318,865	463,909	500,000	461,538	423,077	384,615	346,154	307,692	269,231	230,769	192,308
Interest Accrued		(206)	(3,272)	(12,213)	(26,195)	(36,091)	(40,000)	(36,923)	(33,846)	(30,769)	(27,692)	(24,615)	(21,538)	(18,462)
Interest Paid		0	0	0	0	0	40,000	36,923	33,846	30,769	27,692	24,615	21,538	18,462
Capitalized Interest During Construction (cumulative)		206	3,478	15,691	41,885	77,976								
Project Cash Flows (Straight Line Principal Amortization)														
Revenues (exclusive of VAT)		--	--	3,422	73,581	222,017	264,272	270,350	275,757	281,548	287,461	293,498	299,661	305,954
Total Cash Flows Before Financing		(51,857)	(167,775)	(278,272)	(214,844)	12,588	132,791	176,374	169,681	153,690	152,535	153,499	154,521	155,553
New Debt Financing		32,678	106,691	179,496	145,044	36,091	0	0	0	0	0	0	0	0
New Equity Financing		19,179	61,084	98,804	70,197	0	0	0	0	0	0	0	0	0
Interest Paid		0	0	0	0	0	(40,000)	(36,923)	(33,846)	(30,769)	(27,692)	(24,615)	(21,538)	(18,462)
Principal		0	0	0	0	0	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)
Dividends		0	0	0	0	(48,706)	(54,726)	(100,990)	(97,374)	(84,460)	(86,382)	(90,422)	(94,521)	(98,630)

Payback and Return

	Assumed Equity Return	Total Investment	Year to Payback	Cash Dividends (2000-2014)	Cash Dividends Through 2034
Russian Ownership Group	25.0%	$199,264	2003	$1,162,254	$3,185,700
Foreign	25.0%	$50,000	2003	$291,636	$799,364

FINANCIAL STATEMENTS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
('000 nominal US dollars)	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
SCENARIO: CASE 6 (25% Returns for Russ															
Equity Contributions															
Russian Ownership Group															
Foreign															
Total Dividends to Investors															
Dividends to Investors															
Russian Ownership Group	82,138	83,595	84,805	85,956	87,046	134,193	116,955	116,253	115,482	114,641	113,728	112,740	111,723	110,628	106,918
Foreign	20,610	20,976	21,279	21,568	21,842	33,672	29,347	29,170	28,977	28,766	28,537	28,289	28,034	27,759	26,828
Total Dividends to Investors	102,748	104,571	106,084	107,524	108,888	167,865	146,301	145,423	144,459	143,407	142,265	141,029	139,757	138,387	133,746
Debt Amortization Schedule															
Beginning Balance	192,308	153,846	115,385	76,923	38,462	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Principal Repayment	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Ending Balance	153,846	115,385	76,923	38,462	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Interest Accrued	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Interest Paid	15,385	12,308	9,231	6,154	3,077	0	0	0	0	0	0	0	0	0	0
Capitalized Interest During Construction (cumul															
Project Cash Flows (Straight Line Principal,															
Revenues (exclusive of VAT)	312,379	314,155	315,867	317,514	319,090	320,592	322,016	323,359	324,616	325,784	326,857	327,832	328,704	329,467	330,118
Total Cash Flows Before Financing	156,594	155,340	153,776	152,139	150,426	167,865	146,301	145,423	144,459	143,407	142,265	141,029	139,757	138,387	133,746
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Paid	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Principal	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Dividends	(102,748)	(104,571)	(106,084)	(107,524)	(108,888)	(167,865)	(146,301)	(145,423)	(144,459)	(143,407)	(142,265)	(141,029)	(139,757)	(138,387)	(133,746)
Payback and Return															
Russian Ownership Group															
Foreign															

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FINANCIAL STATEMENTS ('000 nominal US dollars)	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39	Liquidation Value (Working Capital)
SCENARIO: CASE 6 (25% Returns for Russ												
Equity Contributions												
Russian Ownership Group												
Foreign												
Total Dividends to Investors												
Dividends to Investors												
Russian Ownership Group	101,797	98,472	96,261	94,491	92,609	90,610	90,666	88,456	86,138	83,710	81,169	8,868
Foreign	25,543	24,709	24,154	23,710	23,238	22,736	22,750	22,196	21,614	21,005	20,367	2,225
Total Dividends to Investors	127,340	123,180	120,415	118,201	115,847	113,346	113,416	110,651	107,752	104,715	101,536	11,093
Debt Amortization Schedule												
Beginning Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0	
Principal Repayment	0	0	0	0	0	0	0	0	0	0	0	
Ending Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
Interest Accrued	0	0	0	0	0	0	0	0	0	0	0	
Interest Paid	0	0	0	0	0	0	0	0	0	0	0	
Capitalized Interest During Construction (cumul												
Project Cash Flows (Straight Line Principal,												
Revenues (exclusive of VAT)	330,651	331,060	331,341	331,488	331,495	331,356	331,065	330,615	330,001	329,215	328,250	
Total Cash Flows Before Financing	127,340	123,180	120,415	118,201	115,847	113,346	113,416	110,651	107,752	104,715	101,536	
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0	
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0	
Interest Paid	0	0	0	0	0	0	0	0	0	0	0	
Principal	0	0	0	0	0	0	0	0	0	0	0	
Dividends	(127,340)	(123,180)	(120,415)	(118,201)	(115,847)	(113,346)	(113,416)	(110,651)	(107,752)	(104,715)	(101,536)	
Payback and Return												
Russian Ownership Group												
Foreign												

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PROJECT OVERVIEW

Total Project

Sources of Cash:	Nominal US$ ('000)	% Total
Debt	$547,834	70%
Equity	234,786	30%
Total Capital Investment	$782,621	100%

Equity Returns

Russian Equity Investors	15%
Foreign Equity Investors	#VALUE!

	w/o VAT	w/ VAT
Average Tariff ($/kWh) ('95 US$)	$0.0299	$0.0364

Debt Financing

World Bank Loan	$500,000	91%
Export Credit Agency/Vendor Financing	47,834	9%
Other Commercial Bank Financing	0	0%
Total Debt Financing	$547,834	100%

Total Project

Uses of Cash:	Nominal US$ ('000)	% Total
Base Project Cost	$419,039	54%
Duties, Excise, VAT, Special Taxes	173,843	22%
Physical Contingencies	66,156	8%
Real Russian vs. US Escalation	51,829	7%
Inflation	46,221	6%
Interest Paid During Construction	9,403	1%
Capitalized Interest During Const.	75,219	10%
Principal Paid During Construction	15,945	2%
Working Capital (through 2000)	23,947	3%
Less: Internally-Generated Cash	(98,980)	-13%
Total Project Cost to be Financed Externally	$782,621	100%

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Lender Terms

World Bank Loan:
- $500 million draw-down during construction.
- Can be used to finance equipment (which must be procured through international competitive bidding), contingencies, escalation costs, inflation costs, and interest during construction.
- Cannot be used to finance taxes, duties, or equipment which is not procured through international competitive bidding.
- 5 year grace period for repayment of principal and interest.
- 8% interest rate, compounded annually. Actual interest rate may be lower, but lender transaction fees are imbedded in assumed 8% interest rate.
- Interest payable semi-annually.
- 17 year term to maturity.
- Principal amortized, at option of borrower, on straight-line basis in equal semi-annual installments or in equal semi-annual installments of principal and interest.
- Commitment, mobilization and other fees estimated at 2% of principal amount of loan payable at time of closing.
- Other terms and conditions subject to negotiation and may include covenants specifying minimum debt/equity ratio, cash balances, interest coverage ratios, etc. during the loan repayment period.

Export Credit Agency/Vendor Financing:
- $100 million line of credit.
- Can be used to finance up to 85% of equipment supplied from home country of export credit agency.
- 3 year grace period for repayment of principal (interest must be paid during construction period).
- 8% interest rate, compounded annually.
- Interest payable semi-annually.
- 8 year term to maturity.
- Principal amortized on straight-line basis in equal semi-annual installments.

FINANCIAL STATEMENTS ('000 nominal US dollars)	Project Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
		1	2	3	4	5	6	7	8	9	10	11	12	13

SCENARIO: CASE 7 (70/30 Debt/Equity Ratio, $48 mn ECA Loan)

Equity Contributions

	Percent of Total	1996	1997	1998	1999	2000
Russian Ownership Group	100%	16,574	52,951	86,212	79,050	0
Foreign	0%	0	0	0	0	0
Total Dividends to Investors	100%	16,574	52,951	86,212	79,050	0

Dividends to Investors

	2000	2001	2002	2003	2004	2005	2006	2007	2008
Russian Ownership Group	0	2,302	46,111	49,005	51,842	43,922	40,498	43,548	46,587
Foreign	0	0	0	0	0	0	0	0	0
Total Dividends to Investors	0	2,302	46,111	49,005	51,842	43,922	40,498	43,548	46,587

Debt Amortization Schedule

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Beginning Balance	0	35,267	150,353	344,122	503,715	531,889	485,456	439,022	392,588	346,154	307,692	269,231	230,769
Drawdown (inclusive of Capitalized Interest)	35,267	115,086	193,768	167,566	36,146	0	0	0	0	0	0	0	0
Principal Repayment	0	0	0	(7,972)	(7,972)	(46,434)	(46,434)	(46,434)	(46,434)	(38,462)	(38,462)	(38,462)	(38,462)
Ending Balance	35,267	150,353	344,122	503,715	531,889	485,456	439,022	392,588	346,154	307,692	269,231	230,769	192,308
Interest Accrued	(191)	(3,534)	(13,188)	(28,374)	(39,335)	(42,551)	(38,836)	(35,122)	(31,407)	(27,692)	(24,615)	(21,538)	(18,462)
Interest Paid	0	511	1,877	3,827	3,189	42,551	38,836	35,122	31,407	27,692	24,615	21,538	18,462
Capitalized Interest During Construction (cumulative)	191	3,214	14,525	39,072	75,219								

Project Cash Flows (Straight Line Principal Amortization)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Revenues (exclusive of VAT)	–	–	2,732	58,750	177,268	211,007	215,860	220,177	224,801	229,522	234,342	239,263	244,287
Total Cash Flows Before Financing	(51,841)	(168,037)	(279,981)	(234,816)	(23,495)	89,797	131,381	130,561	129,683	110,076	103,575	103,548	103,510
New Debt Financing	35,267	115,086	193,768	167,566	36,146	0	0	0	0	0	0	0	0
New Equity Financing	16,574	52,951	86,212	79,050	0	0	0	0	0	0	0	0	0
Interest Paid	0	(511)	(1,877)	(3,827)	(3,189)	(42,551)	(38,836)	(35,122)	(31,407)	(27,692)	(24,615)	(21,538)	(18,462)
Principal	0	0	0	(7,972)	(7,972)	(46,434)	(46,434)	(46,434)	(46,434)	(38,462)	(38,462)	(38,462)	(38,462)
Dividends	0	0	0	0	0	(2,302)	(46,111)	(49,005)	(51,842)	(43,922)	(40,498)	(43,548)	(46,587)

Payback and Return

	Assumed Equity Return	Total Investment	Year to Payback	Cash Dividends (2000-2014)	Cash Dividends Through 2034
Russian Ownership Group	15.0%	$234,786	2007	$698,117	$2,109,503
Foreign	#VALUE!	$0	nm	$0	$0

FINANCIAL STATEMENTS ('000 nominal US dollars)	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27	2023 28
SCENARIO: CASE 7 (70/30 Debt/Equity Rati															
Equity Contributions															
Russian Ownership Group															
Foreign															
Total Dividends to Investors															
Dividends to Investors															
Russian Ownership Group	49,612	51,084	52,305	53,464	54,558	113,280	91,472	90,364	89,185	87,934	86,607	85,204	83,783	82,282	77,529
Foreign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Dividends to Investors	49,612	51,084	52,305	53,464	54,558	113,280	91,472	90,364	89,185	87,934	86,607	85,204	83,783	82,282	77,529
Debt Amortization Schedule															
Beginning Balance	192,308	153,846	115,385	76,923	38,462	0	0	0	0	0	0	0	0	0	0
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Principal Repayment	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Ending Balance	153,846	115,385	76,923	38,462	0	0	0	0	0	0	0	0	0	0	0
Interest Accrued	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Interest Paid	15,385	12,308	9,231	6,154	3,077	0	0	0	0	0	0	0	0	0	0
Capitalized Interest During Construction (cumul															
Project Cash Flows (Straight Line Principal,															
Revenues (exclusive of VAT)	249,417	250,835	252,203	253,517	254,775	255,975	257,112	258,184	259,188	260,120	260,977	261,756	262,452	263,061	263,581
Total Cash Flows Before Financing	103,458	101,853	99,997	98,079	96,097	113,280	91,472	90,364	89,185	87,934	86,607	85,204	83,783	82,282	77,529
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Paid	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Principal	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Dividends	(49,612)	(51,084)	(52,305)	(53,464)	(54,558)	(113,280)	(91,472)	(90,364)	(89,185)	(87,934)	(86,607)	(85,204)	(83,783)	(82,282)	(77,529)
Payback and Return															
Russian Ownership Group															
Foreign															

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FINANCIAL STATEMENTS ('000 nominal US dollars)	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39	Liquidation Value (Working Capital)
SCENARIO: CASE 7 (70/30 Debt/Equity Rati												
Equity Contributions												
Russian Ownership Group												
Foreign												
Total Dividends to Investors												
Dividends to Investors												
Russian Ownership Group	71,031	66,800	63,986	61,746	59,388	56,910	57,028	54,338	51,542	48,636	45,620	18,390
Foreign	0	0	0	0	0	0	0	0	0	0	0	0
Total Dividends to Investors	71,031	66,800	63,986	61,746	59,388	56,910	57,028	54,338	51,542	48,636	45,620	18,390
Debt Amortization Schedule												
Beginning Balance	0	0	0	0	0	0	0	0	0	0	0	
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0	
Principal Repayment	0	0	0	0	0	0	0	0	0	0	0	
Ending Balance	0	0	0	0	0	0	0	0	0	0	0	
Interest Accrued	0	0	0	0	0	0	0	0	0	0	0	
Interest Paid	0	0	0	0	0	0	0	0	0	0	0	
Capitalized Interest During Construction (cumul												
Project Cash Flows (Straight Line Principal ,												
Revenues (exclusive of VAT)	264,006	264,333	264,558	264,675	264,680	264,569	264,337	263,978	263,487	262,860	262,090	
Total Cash Flows Before Financing	71,031	66,800	63,986	61,746	59,388	56,910	57,028	54,338	51,542	48,636	45,620	
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0	
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0	
Interest Paid	0	0	0	0	0	0	0	0	0	0	0	
Principal	0	0	0	0	0	0	0	0	0	0	0	
Dividends	(71,031)	(66,800)	(63,986)	(61,746)	(59,388)	(56,910)	(57,028)	(54,338)	(51,542)	(48,636)	(45,620)	
Payback and Return												
Russian Ownership Group												
Foreign												

PROJECT OVERVIEW

Total Project

Sources of Cash:	Nominal US$ ('000)	% Total
Debt	$500,000	55%
Equity	402,466	45%
Total Capital Investment	$902,466	100%

Equity Returns

Russian Equity Investors	15%
Foreign Equity Investors	#VALUE!

	w/o VAT	w/ VAT
Average Tariff ($/kWh) ('95 US$)	$0.0341	$0.0415

Debt Financing

World Bank Loan	$500,000	100%
Export Credit Agency/Vendor Financing	0	0%
Other Commecial Bank Financing	0	0%
Total Debt Financing	$500,000	100%

Total Project

Uses of Cash:	Nominal US$ ('000)	% Total
Base Project Cost	$484,766	54%
Duties, Excise, VAT, Special Taxes	206,815	23%
Physical Contingencies	83,592	9%
Real Russian vs. US Escalation	65,907	7%
Inflation	53,578	6%
Interest Paid During Construction	0	0%
Capitalized Interest During Const.	81,148	9%
Principal Paid During Construction	0	0%
Working Capital (through 2000)	19,434	2%
Less: Internally-Generated Cash	(92,774)	-10%
Total Project Cost to be Financed Externally	$902,466	100%

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Lender Terms

World Bank Loan:
- $500 million draw-down during construction.
- Can be used to finance equipment (which must be procured through international competitive bidding), contingencies, escalation costs, inflation costs, and interest during construction.
- Cannot be used to finance taxes, duties, or equipment which is not procured through international competitive bidding.
- 5 year grace period for repayment of principal and interest.
- 8% interest rate, compounded annually. Actual interest rate may be lower, but lender transaction fees are imbedded in assumed 8% interest rate.
- Interest payable semi-annually.
- 17 year term to maturity.
- Principal amortized, at option of borrower, on straight-line basis in equal semi-annual installments or in equal semi-annual installments of principal and interest.
- Commitment, mobilization and other fees estimated at 2% of principal amount of loan payable at time of closing.
- Other terms and conditions subject to negotiation and may include covenants specifying minimum debt/equity ratio, cash balances, interest coverage ratios, etc. during the loan repayment period.

FINANCIAL STATEMENTS ('000 nominal US dollars)	Project Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
		1	2	3	4	5	6	7	8	9	10	11	12	13
SCENARIO: CASE 8 (Including Transmission Line)														
Equity Contributions	Percent of Total													
Russian Ownership Group	100%	41,971	111,062	141,267	108,166	0								
Foreign	0%	0	0	0	0	0								
Total Dividends to Investors	100%	41,971	111,062	141,267	108,166	0								
Dividends to Investors														
Russian Ownership Group						32,653	35,409	81,332	84,381	81,166	65,587	69,224	72,910	76,596
Foreign						0	0	0	0	0	0	0	0	0
Total Dividends to Investors						32,653	35,409	81,332	84,381	81,166	65,587	69,224	72,910	76,596
Debt Amortization Schedule														
Beginning Balance		0	43,958	163,792	324,849	464,040	500,000	461,538	423,077	384,615	346,154	307,692	269,231	230,769
Drawdown (inclusive of Capitalized Interest)		43,958	119,835	161,057	139,191	35,960	0	0	0	0	0	0	0	0
Principal Repayment		0	0	0	0	0	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)
Ending Balance		43,958	163,792	324,849	464,040	500,000	461,538	423,077	384,615	346,154	307,692	269,231	230,769	192,308
Interest Accrued		(278)	(4,251)	(14,038)	(26,621)	(35,960)	(40,000)	(36,923)	(33,846)	(30,769)	(27,692)	(24,615)	(21,538)	(18,462)
Interest Paid		0	0	0	0	0	40,000	36,923	33,846	30,769	27,692	24,615	21,538	18,462
Capitalized Interest During Construction (cumulative)		278	4,529	18,567	45,188	81,148								
Project Cash Flows (Straight Line Principal Amortization)														
Revenues (exclusive of VAT)		--	--	3,115	66,977	202,092	240,554	246,087	251,009	256,280	261,662	267,157	272,767	278,495
Total Cash Flows Before Financing		(85,929)	(230,896)	(302,324)	(247,356)	(3,307)	113,871	156,717	156,688	150,397	131,741	132,301	132,910	133,519
New Debt Financing		43,958	119,835	161,057	139,191	35,960	0	0	0	0	0	0	0	0
New Equity Financing		41,971	111,062	141,267	108,166	0	0	0	0	0	0	0	0	0
Interest Paid		0	0	0	0	0	(40,000)	(36,923)	(33,846)	(30,769)	(27,692)	(24,615)	(21,538)	(18,462)
Principal		0	0	0	0	0	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)
Dividends		0	0	0	0	(32,653)	(35,409)	(81,332)	(84,381)	(81,166)	(65,587)	(69,224)	(72,910)	(76,596)

Payback and Return

	Assumed Equity Return	Total Investment	Year to Payback	Cash Dividends (2000-2014)	Cash Dividends Through 2034
Russian Ownership Group	15.0%	$402,466	2006	$1,160,905	$3,208,359
Foreign	#VALUE!	$0	nm	$0	$0

FINANCIAL STATEMENTS ('000 nominal US dollars)	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27	2023 28
SCENARIO: CASE 8 (Including Transmissio															
Equity Contributions															
Russian Ownership Group															
Foreign															
Total Dividends to Investors															
Dividends to Investors															
Russian Ownership Group	80,281	82,001	83,437	84,806	86,103	145,021	123,402	122,475	121,469	120,382	119,211	117,954	116,670	115,295	109,832
Foreign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Dividends to Investors	80,281	82,001	83,437	84,806	86,103	145,021	123,402	122,475	121,469	120,382	119,211	117,954	116,670	115,295	109,832
Debt Amortization Schedule															
Beginning Balance	192,308	153,846	115,385	76,923	38,462	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Principal Repayment	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Ending Balance	153,846	115,385	76,923	38,462	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Interest Accrued	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Interest Paid	15,385	12,308	9,231	6,154	3,077	0	0	0	0	0	0	0	0	0	0
Capitalized Interest During Construction (cumul															
Project Cash Flows (Straight Line Principal,															
Revenues (exclusive of VAT)	284,343	285,960	287,519	289,017	290,452	291,819	293,116	294,338	295,483	296,545	297,522	298,410	299,203	299,898	300,491
Total Cash Flows Before Financing	134,127	132,770	131,130	129,421	127,642	145,021	123,402	122,475	121,469	120,382	119,211	117,954	116,670	115,295	109,832
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Paid	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Principal	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Dividends	(80,281)	(82,001)	(83,437)	(84,806)	(86,103)	(145,021)	(123,402)	(122,475)	(121,469)	(120,382)	(119,211)	(117,954)	(116,670)	(115,295)	(109,832)
Payback and Return															
Russian Ownership Group															
Foreign															

FINANCIAL STATEMENTS ('000 nominal US dollars)	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39	Liquidation Value (Working Capital)
SCENARIO: CASE 8 (Including Transmissio												
Equity Contributions												
Russian Ownership Group												
Foreign												
Total Dividends to Investors												
Dividends to Investors												
Russian Ownership Group	102,426	98,076	95,289	93,063	90,707	88,216	88,308	85,576	82,723	79,744	76,638	20,270
Foreign	0	0	0	0	0	0	0	0	0	0	0	0
Total Dividends to Investors	102,426	98,076	95,289	93,063	90,707	88,216	88,308	85,576	82,723	79,744	76,638	20,270
Debt Amortization Schedule												
Beginning Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0	
Principal Repayment	0	0	0	0	0	0	0	0	0	0	0	
Ending Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
Interest Accrued	0	0	0	0	0	0	0	0	0	0	0	
Interest Paid	0	0	0	0	0	0	0	0	0	0	0	
Capitalized Interest During Construction (cumul												
Project Cash Flows (Straight Line Principal,												
Revenues (exclusive of VAT)	300,975	301,348	301,604	301,738	301,744	301,617	301,352	300,943	300,384	299,668	298,791	
Total Cash Flows Before Financing	102,426	98,076	95,289	93,063	90,707	88,216	88,308	85,576	82,723	79,744	76,638	
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0	
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0	
Interest Paid	0	0	0	0	0	0	0	0	0	0	0	
Principal	0	0	0	0	0	0	0	0	0	0	0	
Dividends	(102,426)	(98,076)	(95,289)	(93,063)	(90,707)	(88,216)	(88,308)	(85,576)	(82,723)	(79,744)	(76,638)	
Payback and Return												
Russian Ownership Group												
Foreign												

PROJECT OVERVIEW

Total Project

Sources of Cash:	Nominal US$ ('000)	% Total
Debt	$500,000	51%
Equity	473,445	49%
Total Capital Investment	$973,445	100%

Total Project

Uses of Cash:	Nominal US$ ('000)	% Total
Base Project Cost	$522,766	54%
Duties, Excise, VAT, Special Taxes	220,910	23%
Physical Contingencies	91,122	9%
Real Russian vs. US Escalation	72,031	7%
Inflation	57,070	6%
Interest Paid During Construction	0	0%
Capitalized Interest During Const.	84,195	9%
Principal Paid During Construction	0	0%
Working Capital (through 2000)	19,987	2%
Less: Internally-Generated Cash	(94,638)	-10%
Total Project Cost to be Financed Externally	$973,445	100%

Equity Returns

Russian Equity Investors	15%
Foreign Equity Investors	#VALUE!

	w/o VAT	w/ VAT
Average Tariff ($/kWh) ('95 US$)	$0.0363	$0.0441

Debt Financing

World Bank Loan	$500,000	100%
Export Credit Agency/Vendor Financing	0	0%
Other Commercial Bank Financing	0	0%
Total Debt Financing	$500,000	100%

<u>Lender Terms</u>

World Bank Loan:

- $500 million draw-down during construction.
- Can be used to finance equipment (which must be procured through international competitive bidding), contingencies, escalation costs, inflation costs, and interest during construction.
- Cannot be used to finance taxes, duties, or equipment which is not procured through international competitive bidding.
- 5 year grace period for repayment of principal and interest.
- 8% interest rate, compounded annually. Actual interest rate may be lower, but lender transaction fees are imbedded in assumed 8% interest rate.
- Interest payable semi-annually.
- 17 year term to maturity.
- Principal amortized, at option of borrower, on straight-line basis in equal semi-annual installments or in equal semi-annual installments of principal and interest.
- Commitment, mobilization and other fees estimated at 2% of principal amount of loan payable at time of closing.
- Other terms and conditions subject to negotiation and may include covenants specifying minimum debt/equity ratio, cash balances, interest coverage ratios, etc. during the loan repayment period.

FINANCIAL STATEMENTS ('000 nominal US dollars)	Project Year	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11	2007 12	2008 13
SCENARIO: CASE 9 (Including Transmission Line and Gas Pipeline)														
Equity Contributions														
	Percent of Total													
Russian Ownership Group	100%	59,597	144,297	154,059	115,491	0								
Foreign	0%	0	0	0	0	0								
Total Dividends to Investors	100%	59,597	144,297	154,059	115,491	0								
Dividends to Investors														
Russian Ownership Group						43,755	48,511	94,971	98,314	90,972	80,146	84,105	88,119	92,140
Foreign						0	0	0	0	0	0	0	0	0
Total Dividends to Investors						43,755	48,511	94,971	98,314	90,972	80,146	84,105	88,119	92,140
Debt Amortization Schedule														
Beginning Balance		0	52,674	184,423	335,341	464,150	500,000	461,538	423,077	384,615	346,154	307,692	269,231	230,769
Drawdown (inclusive of Capitalized Interest)		52,674	131,749	150,917	128,810	35,850	0	0	0	0	0	0	0	0
Principal Repayment		0	0	0	0	0	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)
Ending Balance		52,674	184,423	335,341	464,150	500,000	461,538	423,077	384,615	346,154	307,692	269,231	230,769	192,308
Interest Accrued		(333)	(5,019)	(15,614)	(27,379)	(35,850)	(40,000)	(36,923)	(33,846)	(30,769)	(27,692)	(24,615)	(21,538)	(18,462)
Interest Paid		0	0	0	0	0	40,000	36,923	33,846	30,769	27,692	24,615	21,538	18,462
Capitalized Interest During Construction (cumulative)		333	5,352	20,966	48,345	84,195								
Project Cash Flows (Straight Line Principal Amortization)														
Revenues (exclusive of VAT)		–	–	3,313	71,242	214,961	255,872	261,757	266,993	272,599	278,324	284,169	290,136	296,229
Total Cash Flows Before Financing		(112,272)	(276,046)	(304,977)	(244,300)	7,906	126,972	170,356	170,621	160,203	146,300	147,182	148,119	149,063
New Debt Financing		52,674	131,749	150,917	128,810	35,850	0	0	0	0	0	0	0	0
New Equity Financing		59,597	144,297	154,059	115,491	0	0	0	0	0	0	0	0	0
Interest Paid		0	0	0	0	0	(40,000)	(36,923)	(33,846)	(30,769)	(27,692)	(24,615)	(21,538)	(18,462)
Principal		0	0	0	0	0	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)
Dividends		0	0	0	0	(43,755)	(48,511)	(94,971)	(98,314)	(90,972)	(80,146)	(84,105)	(88,119)	(92,140)

Payback and Return

	Assumed Equity Return	Total Investment	Year to Payback	Cash Dividends (2000-2014)	Cash Dividends Through 2034
Russian Ownership Group	15.0%	$473,445	2006	$1,379,713	$3,756,573
Foreign	#VALUE!	$0	nm	$0	$0

FINANCIAL STATEMENTS ('000 nominal US dollars)	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27	2023 28
SCENARIO: CASE 9 (Including Transmissio															
Equity Contributions															
Russian Ownership Group															
Foreign															
Total Dividends to Investors															
Dividends to Investors															
Russian Ownership Group	96,166	98,014	99,562	101,038	102,440	161,458	139,936	139,103	138,185	137,183	136,092	134,910	133,696	132,385	126,483
Foreign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Dividends to Investors	96,166	98,014	99,562	101,038	102,440	161,458	139,936	139,103	138,185	137,183	136,092	134,910	133,696	132,385	126,483
Debt Amortization Schedule															
Beginning Balance	192,308	153,846	115,385	76,923	38,462	0	0	0	0	0	0	0	0	0	0
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Principal Repayment	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Ending Balance	153,846	115,385	76,923	38,462	0	0	0	0	0	0	0	0	0	0	0
Interest Accrued	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Interest Paid	15,385	12,308	9,231	6,154	3,077	0	0	0	0	0	0	0	0	0	0
Capitalized Interest During Construction (cumul															
Project Cash Flows (Straight Line Principal															
Revenues (exclusive of VAT)	302,450	304,170	305,828	307,422	308,947	310,402	311,781	313,081	314,299	315,429	316,468	317,412	318,256	318,995	319,625
Total Cash Flows Before Financing	150,013	148,784	147,254	145,654	143,979	161,458	139,936	139,103	138,185	137,183	136,092	134,910	133,696	132,385	126,483
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Paid	(15,385)	(12,308)	(9,231)	(6,154)	(3,077)	0	0	0	0	0	0	0	0	0	0
Principal	(38,462)	(38,462)	(38,462)	(38,462)	(38,462)	0	0	0	0	0	0	0	0	0	0
Dividends	(96,166)	(98,014)	(99,562)	(101,038)	(102,440)	(161,458)	(139,936)	(139,103)	(138,185)	(137,183)	(136,092)	(134,910)	(133,696)	(132,385)	(126,483)
Payback and Return															
Russian Ownership Group															
Foreign															

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FINANCIAL STATEMENTS (000 nominal US dollars)	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39	Liquidation Value (Working Capital)
SCENARIO: CASE 9 (Including Transmissio												
Equity Contributions												
Russian Ownership Group												
Foreign												
Total Dividends to Investors												
Dividends to Investors												
Russian Ownership Group	118,619	114,290	111,517	109,298	106,943	104,446	104,524	101,771	98,888	95,871	92,718	21,245
Foreign	0	0	0	0	0	0	0	0	0	0	0	0
Total Dividends to Investors	118,619	114,290	111,517	109,298	106,943	104,446	104,524	101,771	98,888	95,871	92,718	21,245
Debt Amortization Schedule												
Beginning Balance	0	0	0	0	0	0	0	0	0	0	0	
Drawdown (inclusive of Capitalized Interest)	0	0	0	0	0	0	0	0	0	0	0	
Principal Repayment	0	0	0	0	0	0	0	0	0	0	0	
Ending Balance	0	0	0	0	0	0	0	0	0	0	0	
Interest Accrued	0	0	0	0	0	0	0	0	0	0	0	
Interest Paid	0	0	0	0	0	0	0	0	0	0	0	
Capitalized Interest During Construction (cumul												
Project Cash Flows (Straight Line Principal,												
Revenues (exclusive of VAT)	320,141	320,538	320,810	320,952	320,958	320,824	320,542	320,107	319,512	318,751	317,817	
Total Cash Flows Before Financing	118,619	114,290	111,517	109,298	106,943	104,446	104,524	101,771	98,888	95,871	92,718	
New Debt Financing	0	0	0	0	0	0	0	0	0	0	0	
New Equity Financing	0	0	0	0	0	0	0	0	0	0	0	
Interest Paid	0	0	0	0	0	0	0	0	0	0	0	
Principal	0	0	0	0	0	0	0	0	0	0	0	
Dividends	(118,619)	(114,290)	(111,517)	(109,298)	(106,943)	(104,446)	(104,524)	(101,771)	(98,888)	(95,871)	(92,718)	
Payback and Return												
Russian Ownership Group												
Foreign												

APPENDIX B

ECONOMIC ANALYSIS

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APPENDIX B -- ECONOMIC MODEL

CONTENTS

APPENDIX B.1 – ECONOMIC MODEL, BASE CASE

ECONOMIC RATE OF RETURN	20.2%
Net Present Value at 15% Discount Rate (1995 US $ '000)	$191,358

	1996-1997	1998	1999	2000	2001	2002
ECONOMIC BENEFIT SUMMARY						
Quantity of Substituted Energy (GWh)	0	0	1,914	3,904	3,638	3,173
Quantity of Incremental Energy (GWh)	0	265	1,177	2,291	2,927	3,331
Energy Lost In Transmission/Distribution (GWh)	0	40	176	342	437	498
Total Energy Supplied (GWh)	0	305	3,267	6,537	7,002	7,002
Benefit of Substituted Energy (1995 US $ '000)	$0	$0	$777	$13,561	$13,654	$12,488
Benefit of Incremental Energy (1995 US $ '000)	0	12,866	57,571	112,708	144,459	164,911
Total Benefit of Energy Supplied (1995 US $ '000)	$0	$12,866	$58,348	$126,269	$158,113	$177,399
ECONOMIC COST SUMMARY						
Total Capital Costs	$217,416	$166,050	$135,689	$39,150	$0	$0
Total Production Costs	0	6,898	50,762	77,284	82,189	82,725
Total Costs	$217,416	$172,947	$186,451	$116,434	$82,189	$82,725
ANNUAL NET BENEFIT	($217,416)	($160,081)	($128,103)	$9,835	$75,925	$94,673

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	ECONOMIC RATE OF RETURN ('000 real 1995 US dollars)	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
	Project Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13
1	**BENEFIT SUMMARY**														
2															
3	**Incremental Benefit Level**		$0	$0	$6,671	$30,258	$59,874	$77,117	$88,590	$111,309	$140,494	$158,886	$161,326	$163,781	$166,300
4	Industry		0	0	2,867	12,583	24,175	30,732	34,586	42,636	52,799	58,486	59,325	60,168	61,033
5	Agriculture		0	0	1,322	5,977	11,871	15,334	17,684	22,307	28,268	32,032	32,537	33,045	33,566
6	Transport		0	0	2,006	8,753	16,788	21,277	24,051	29,506	36,386	40,151	40,293	40,428	40,569
7	Residential/Other														
8															
9	**Substitute Benefit Level**														
10	All Customer Categories		0	0	0	777	13,561	13,654	12,488	9,229	4,559	1,654	1,347	1,032	698
11															
12	Total Benefit Level		$0	$0	$12,866	$58,348	$126,269	$158,113	$177,399	$214,968	$262,506	$291,210	$294,828	$298,454	$302,165
13															
14	**COST SUMMARY**														
15															
16	Total Capital Costs		$57,155	$160,262	$166,050	$135,689	$39,150	$0	$0	$0	$0	$0	$0	$0	$0
17															
18	Total Production Costs		0	0	6,898	50,762	77,284	82,189	82,725	83,231	83,708	84,840	85,639	86,439	87,241
19															
20	Total Costs		$57,155	$160,262	$172,947	$186,451	$116,434	$82,189	$82,725	$83,231	$83,708	$84,840	$85,639	$86,439	$87,241
21															
22															
23															
24	Annual Net Benefit		(57,155)	(160,262)	(160,081)	(128,103)	9,835	75,925	94,673	131,758	178,799	206,370	209,190	212,015	214,924
25															
26	**Net Present Value (Discount Rate = 15%)**		$191,358												
27															
28	**Economic Rate of Return**		20.2%												

	ECONOMIC RATE OF RETURN ('000 real 1995 US dollars) Project Year	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27
1	**BENEFIT SUMMARY**														
2															
3	**Incremental Benefit Level**	$168,834	$168,352	$165,296	$162,239	$159,183	$156,127	$153,070	$150,014	$146,957	$143,901	$140,844	$137,788	$134,732	$131,675
4	Industry	61,902	61,666	60,546	59,427	58,307	57,188	56,068	54,949	53,829	52,710	51,590	50,471	49,351	48,231
5	Agriculture	34,090	34,006	33,388	32,771	32,154	31,536	30,919	30,301	29,684	29,067	28,449	27,832	27,215	26,597
6	Transport	40,702	40,107	39,379	38,651	37,923	37,195	36,467	35,738	35,010	34,282	33,554	32,826	32,098	31,370
7	Residential/Other														
8															
9	**Substitute Benefit Level**														
10	All Customer Categories	356	0	0	0	0	0	0	0	0	0	0	0	0	0
11															
12	**Total Benefit Level**	$305,884	$304,131	$298,610	$293,088	$287,567	$282,045	$276,524	$271,002	$265,481	$259,959	$254,438	$248,916	$243,395	$237,873
13															
14	**COST SUMMARY**														
15															
16	Total Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17															
18	Total Production Costs	88,047	87,463	86,854	86,222	85,567	84,889	84,188	83,464	82,717	81,946	81,151	80,332	79,445	78,535
19															
20	**Total Costs**	$88,047	$87,463	$86,854	$86,222	$85,567	$84,889	$84,188	$83,464	$82,717	$81,946	$81,151	$80,332	$79,445	$78,535
21															
22															
23															
24	**Annual Net Benefit**	217,838	216,668	211,756	206,867	202,000	197,156	192,336	187,538	182,764	178,014	173,287	168,584	163,950	159,338
25															
26	**Net Present Value (Discount Rate = 15%)**														
27															
28	**Economic Rate of Return**														

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	ECONOMIC RATE OF RETURN ('000 real 1995 US dollars) Project Year	2023 28	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39
1	**BENEFIT SUMMARY**												
2													
3	**Incremental Benefit Level**	$128,619	$125,562	$122,506	$119,449	$116,393	$113,337	$110,280	$107,224	$104,167	$101,111	$98,054	$94,998
4	Industry	47,112	45,992	44,873	43,753	42,634	41,514	40,395	39,275	38,156	37,036	35,916	34,797
5	Agriculture	25,980	25,362	24,745	24,128	23,510	22,893	22,276	21,658	21,041	20,423	19,806	19,189
6	Transport	30,641	29,913	29,185	28,457	27,729	27,001	26,273	25,544	24,816	24,088	23,360	22,632
7	Residential/Other												
8													
9	**Substitute Benefit Level**												
10	All Customer Categories	0	0	0	0	0	0	0	0	0	0	0	0
11													
12	**Total Benefit Level**	$232,352	$226,830	$221,309	$215,787	$210,266	$204,744	$199,223	$193,701	$188,180	$182,658	$177,137	$171,616
13													
14	**COST SUMMARY**												
15													
16	Total Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17													
18	Total Production Costs	77,603	76,647	75,667	74,662	73,621	72,554	71,463	70,346	69,203	68,034	66,838	65,615
19													
20	**Total Costs**	$77,603	$76,647	$75,667	$74,662	$73,621	$72,554	$71,463	$70,346	$69,203	$68,034	$66,838	$65,615
21													
22													
23													
24	**Annual Net Benefit**	154,749	150,184	145,642	141,125	136,645	132,190	127,760	123,355	118,977	114,624	110,299	106,000
25													
26	**Net Present Value (Discount Rate = 15%)**												
27													
28	**Economic Rate of Return**												

ECONOMIC BENEFIT CALCULATIONS By Customer Category and By Year	1995 0	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11	2007 12	2008 13
1 **Total Supplied (GWh) at the busbar (after 1.56% internal losses)**		0	0	305	3,267	6,537	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002
2														
3 **Unserved Energy Before Losses (from ICF model)**		0	0	305	1,353	2,633	3,364	3,829	4,755	5,934	6,630	6,703	6,776	6,851
4														
5 **Substituted Energy (GWh) (line 1 minus line 3)**		0	0	0	1,914	3,904	3,638	3,173	2,247	1,068	372	299	226	151
6 Cost Savings ($/kWh) (See Economic Costs Calculations, Line:) 113		nm	nm	nm	0.00041	0.00347	0.00375	0.00394	0.00411	0.00427	0.00445	0.00451	0.00456	0.00462
7 **Value of Substituted Energy ($ '000)**		0	0	0	777	13,561	13,654	12,488	9,229	4,559	1,654	1,347	1,032	698
8														
9 **Incremental Energy Before Losses (line 1 minus line 5)**		0	0	305	1,353	2,633	3,364	3,829	4,755	5,934	6,630	6,703	6,776	6,851
10 Transmission/Distribution Loss 13%		0	0	40	176	342	437	498	618	771	862	871	881	891
11 **Incremental Energy After Losses**		0	0	265	1,177	2,291	2,927	3,331	4,137	5,163	5,768	5,832	5,895	5,960
12														
13 **Percentage Consumption by Classification**														
14 Industry	33.7%	34.8%	35.3%	36.3%	37.0%	37.7%	38.0%	38.3%	38.8%	39.2%	39.7%	39.9%	40.0%	40.2%
15 Agriculture	18.5%	18.3%	18.0%	17.9%	17.7%	17.4%	17.3%	17.1%	17.0%	16.9%	16.7%	16.8%	16.9%	16.9%
16 Transport	6.8%	6.9%	7.0%	7.2%	7.3%	7.5%	7.5%	7.6%	7.8%	7.9%	8.0%	8.0%	8.1%	8.1%
17 Residential/Other	41.0%	39.9%	39.6%	38.7%	38.0%	37.5%	37.2%	36.9%	36.5%	36.0%	35.6%	35.3%	35.0%	34.8%
18														
19 **Consumption by Classification (GWh)**														
20 Industry		0	0	96	436	863	1111	1276	1604	2024	2289	2324	2359	2396
21 Agriculture		0	0	47	208	399	507	571	704	872	966	980	993	1008
22 Transport		0	0	19	86	171	221	255	321	407	461	469	476	484
23 Residential/Other		0	0	103	447	858	1087	1229	1508	1860	2052	2059	2066	2073
24 Total Consumption		0	0	265	1,177	2,291	2,927	3,331	4,137	5,163	5,768	5,832	5,895	5,960
25														
26 **Tariff by Classification (Roubles)**	April '95	Sept. '95		Converted	April '95	Sept. '95	Avg. '95							
27 Industry	150	298		to 1995	0.0506	0.0694	0.0600							
28 Agriculture	101	260		Dollars	0.0341	0.0606	0.0473							
29 Transport	150	298			0.0506	0.0694	0.0600							
30 Residential/Other	36	84			0.0121	0.0196	0.0159							
31														
32 **PPP Ratio of Price Index (3 month average)**	(Feb-Apr)	(Aug-Oct)												
33 Industry	2,963	4,293												
34 Agriculture	2,963	4,293												
35 Transport	2,963	4,293												
36 Residential/Other	2,963	4,293												
37														
38 **Tariff by Classification (September 1995 Prices Used Throughout)**														
39 Industry	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694
40 Agriculture	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606
41 Transport	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694
42 Residential/Other	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196
43														

ECONOMIC BENEFIT CALCULATIONS By Customer Category and By Year	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27
1 **Total Supplied (GWh) at the busbar (after 1.56% internal loss**	7,002	6,877	6,752	6,627	6,503	6,378	6,253	6,128	6,003	5,878	5,753	5,629	5,504	5,379
2														
3 **Unserved Energy Before Losses (from ICF model)**	6,926	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002
4														
5 **Substituted Energy (GWh) (line 1 minus line 3)**	76	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Cost Savings ($/kWh) (See Economic Costs Calculations, Line:)	0.00468	0.00473	0.00478	0.00484	0.00489	0.00494	0.00499	0.00504	0.00509	0.00514	0.00519	0.00524	0.00527	0.00530
7 **Value of Substituted Energy ($ '000)**	356	0	0	0	0	0	0	0	0	0	0	0	0	0
8														
9 **Incremental Energy Before Losses (line 1 minus line 5)**	6,926	6,877	6,752	6,627	6,503	6,378	6,253	6,128	6,003	5,878	5,753	5,629	5,504	5,379
10 Transmission/Distribution Loss 13%	900	894	878	862	845	829	813	797	780	764	748	732	715	699
11 **Incremental Energy After Losses**	6,026	5,983	5,875	5,766	5,657	5,549	5,440	5,331	5,223	5,114	5,006	4,897	4,788	4,680
12														
13 **Percentage Consumption by Classification**														
14 Industry	40.4%	40.5%	40.5%	40.5%	40.5%	40.5%	40.5%	40.5%	40.5%	40.5%	40.5%	40.5%	40.5%	40.5%
15 Agriculture	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%
16 Transport	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%
17 Residential/Other	34.5%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%
18														
19 **Consumption by Classification (GWh)**														
20 Industry	2432	2425	2381	2337	2293	2249	2205	2161	2117	2073	2029	1985	1941	1897
21 Agriculture	1022	1018	1000	981	963	944	926	907	889	870	852	833	815	796
22 Transport	491	490	481	472	463	454	445	437	428	419	410	401	392	383
23 Residential/Other	2080	2050	2013	1975	1938	1901	1864	1826	1789	1752	1715	1678	1640	1603
24 Total Consumption	6,026	5,983	5,875	5,766	5,657	5,549	5,440	5,331	5,223	5,114	5,006	4,897	4,788	4,680
25														
26 **Tariff by Classification (Roubles)**														
27 Industry														
28 Agriculture														
29 Transport														
30 Residential/Other														
31														
32 **PPP Ratio of Price Index (3 month average)**														
33 Industry														
34 Agriculture														
35 Transport														
36 Residential/Other														
37														
38 **Tariff by Classification (September 1995 Prices Used Throug**														
39 Industry	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694
40 Agriculture	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606
41 Transport	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694
42 Residential/Other	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196
43														

ECONOMIC BENEFIT CALCULATIONS By Customer Category and By Year	2023 28	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39
1 **Total Supplied (GWh) at the busbar (after 1.56% internal loss**	5,254	5,129	5,004	4,880	4,755	4,630	4,505	4,380	4,255	4,130	4,006	3,881
2												
3 **Unserved Energy Before Losses (from ICF model)**	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002
4												
5 **Substituted Energy (GWh) (line 1 minus line 3)**	0	0	0	0	0	0	0	0	0	0	0	0
6 Cost Savings ($/kWh) (See Economic Costs Calculations, Line:)	0.00534	0.00537	0.00540	0.00544	0.00547	0.00550	0.00553	0.00556	0.00560	0.00563	0.00566	0.00570
7 **Value of Substituted Energy ($ '000)**	0	0	0	0	0	0	0	0	0	0	0	0
8												
9 **Incremental Energy Before Losses (line 1 minus line 5)**	5,254	5,129	5,004	4,880	4,755	4,630	4,505	4,380	4,255	4,130	4,006	3,881
10 Transmission/Distribution Loss 13%	683	667	651	634	618	602	586	569	553	537	521	504
11 **Incremental Energy After Losses**	4,571	4,462	4,354	4,245	4,137	4,028	3,919	3,811	3,702	3,593	3,485	3,376
12												
13 **Percentage Consumption by Classification**												
14 Industry	40.5%	40.5%	40.5%	40.5%	40.5%	40.5%	40.5%	40.5%	40.5%	40.5%	40.5%	40.5%
15 Agriculture	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%	17.0%
16 Transport	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%
17 Residential/Other	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%	34.3%
18												
19 **Consumption by Classification (GWh)**												
20 Industry	1853	1809	1765	1721	1677	1633	1589	1545	1501	1457	1413	1369
21 Agriculture	778	759	741	722	704	685	667	648	630	612	593	575
22 Transport	374	365	356	348	339	330	321	312	303	294	285	276
23 Residential/Other	1566	1529	1492	1454	1417	1380	1343	1305	1268	1231	1194	1157
24 Total Consumption	4,571	4,462	4,354	4,245	4,137	4,028	3,919	3,811	3,702	3,593	3,485	3,376
25												
26 **Tariff by Classification (Roubles)**												
27 Industry												
28 Agriculture												
29 Transport												
30 Residential/Other												
31												
32 **PPP Ratio of Price Index (3 month average)**												
33 Industry												
34 Agriculture												
35 Transport												
36 Residential/Other												
37												
38 **Tariff by Classification (September 1995 Prices Used Throug**												
39 Industry	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694
40 Agriculture	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606
41 Transport	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694
42 Residential/Other	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196
43												

ECONOMIC BENEFIT CALCULATIONS By Customer Category and By Year	1995 0	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11	2007 12	2008 13
44 **Economic Benefit Calculations -- Inputs**														
45 **Industry**														
46 Current Price ($/kWh)				$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694
47 Total Supplied Quantity in N. Caucasus (GWh)				16,235	17,119	17,912	18,598	19,363	20,160	20,989	21,896	22,224	22,551	22,879
48 Supplied Quantity w/o New Plant (GWh) (less incremental energy)				16,139	16,683	17,049	17,487	18,087	18,556	18,966	19,607	19,899	20,192	20,484
49 **Agriculture**														
50 Current Price ($/kWh)				$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606
51 Total Supplied Quantity in N. Caucasus (GWh)				7,998	8,159	8,289	8,495	8,664	8,851	9,041	9,238	9,366	9,495	9,624
52 Supplied Quantity w/o New Plant (GWh) (less incremental energy)				7,950	7,952	7,890	7,987	8,093	8,147	8,169	8,272	8,387	8,501	8,616
53 **Transport**														
54 Current Price ($/kWh)				$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694
55 Total Supplied Quantity in N. Caucasus (GWh)				3,218	3,381	3,551	3,698	3,865	4,040	4,223	4,414	4,482	4,550	4,618
56 Supplied Quantity w/o New Plant (GWh) (less incremental energy)				3,199	3,295	3,380	3,477	3,611	3,719	3,816	3,953	4,013	4,074	4,134
57 **Residential**														
58 Current Price ($/kWh)				$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196
59 Total Supplied Quantity in N. Caucasus (GWh)				17,319	17,569	17,817	18,204	18,650	18,959	19,285	19,629	19,682	19,724	19,757
60 Supplied Quantity w/o New Plant (GWh) (less incremental energy)				17,216	17,121	16,959	17,116	17,420	17,451	17,425	17,577	17,623	17,658	17,684
61														
62 **Economic Benefit Calculations -- Outputs**														
63 **Industry**														
64 Economic Benefit of Marginal Power of New Plant ($ million)				6.67	30.26	59.87	77.12	88.59	111.31	140.49	158.89	161.33	163.78	166.30
65 **Agriculture**														
66 Economic Benefit of Marginal Power of New Plant ($ million)				2.87	12.58	24.18	30.73	34.59	42.64	52.80	58.49	59.32	60.17	61.03
67 **Transport**														
68 Economic Benefit of Marginal Power of New Plant ($ million)				1.32	5.98	11.87	15.33	17.68	22.31	28.27	32.03	32.54	33.04	33.57
69 **Residential**														
70 Economic Benefit of Marginal Power of New Plant ($ million)				2.01	8.75	16.79	21.28	24.05	29.51	36.39	40.15	40.29	40.43	40.57
71														
72 **Total Economic Benefit of Marginal Power ($ million)**				$12.87	$57.57	$112.71	$144.46	$164.91	$205.76	$257.95	$289.56	$293.48	$297.42	$301.47

ECONOMIC BENEFIT CALCULATIONS By Customer Category and By Year	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27
44 **Economic Benefit Calculations -- Inputs**														
45 **Industry**														
46 Current Price ($/kWh)	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694
47 Total Supplied Quantity in N. Caucasus (GWh)	23,207	23,535	23,535	23,535	23,535	23,535	23,535	23,535	23,535	23,535	23,535	23,535	23,535	23,535
48 Supplied Quantity w/o New Plant (GWh) (less incremental energy)	20,775	21,110	21,154	21,198	21,242	21,286	21,330	21,374	21,418	21,462	21,506	21,550	21,594	21,638
49 **Agriculture**														
50 Current Price ($/kWh)	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606
51 Total Supplied Quantity in N. Caucasus (GWh)	9,752	9,881	9,881	9,881	9,881	9,881	9,881	9,881	9,881	9,881	9,881	9,881	9,881	9,881
52 Supplied Quantity w/o New Plant (GWh) (less incremental energy)	8,730	8,862	8,881	8,899	8,918	8,936	8,955	8,973	8,992	9,010	9,029	9,047	9,066	9,084
53 **Transport**														
54 Current Price ($/kWh)	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694
55 Total Supplied Quantity in N. Caucasus (GWh)	4,686	4,754	4,754	4,754	4,754	4,754	4,754	4,754	4,754	4,754	4,754	4,754	4,754	4,754
56 Supplied Quantity w/o New Plant (GWh) (less incremental energy)	4,195	4,264	4,273	4,282	4,291	4,300	4,308	4,317	4,326	4,335	4,344	4,353	4,362	4,371
57 **Residential**														
58 Current Price ($/kWh)	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196
59 Total Supplied Quantity in N. Caucasus (GWh)	19,784	19,891	19,891	19,891	19,891	19,891	19,891	19,891	19,891	19,891	19,891	19,891	19,891	19,891
60 Supplied Quantity w/o New Plant (GWh) (less incremental energy)	17,704	17,841	17,879	17,916	17,953	17,990	18,027	18,065	18,102	18,139	18,176	18,213	18,251	18,288
61														
62 **Economic Benefit Calculations -- Outputs**														
63 **Industry**														
64 Economic Benefit of Marginal Power of New Plant ($ million)	168.83	168.35	165.30	162.24	159.18	156.13	153.07	150.01	146.96	143.90	140.84	137.79	134.73	131.68
65 **Agriculture**														
66 Economic Benefit of Marginal Power of New Plant ($ million)	61.90	61.67	60.55	59.43	58.31	57.19	56.07	54.95	53.83	52.71	51.59	50.47	49.35	48.23
67 **Transport**														
68 Economic Benefit of Marginal Power of New Plant ($ million)	34.09	34.01	33.39	32.77	32.15	31.54	30.92	30.30	29.68	29.07	28.45	27.83	27.21	26.60
69 **Residential**														
70 Economic Benefit of Marginal Power of New Plant ($ million)	40.70	40.11	39.38	38.65	37.92	37.19	36.47	35.74	35.01	34.28	33.55	32.83	32.10	31.37
71														
72 Total Economic Benefit of Marginal Power ($ million)	$305.53	$304.13	$298.61	$293.09	$287.57	$282.05	$276.52	$271.00	$265.48	$259.96	$254.44	$248.92	$243.39	$237.87

ECONOMIC BENEFIT CALCULATIONS By Customer Category and By Year	2023 28	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39
44 **Economic Benefit Calculations -- Inputs**												
45 **Industry**												
46 Current Price ($/kWh)	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694
47 Total Supplied Quantity in N. Caucasus (GWh)	23,535	23,535	23,535	23,535	23,535	23,535	23,535	23,535	23,535	23,535	23,535	23,535
48 Supplied Quantity w/o New Plant (GWh) (less incremental energy)	21,682	21,726	21,770	21,814	21,858	21,902	21,947	21,991	22,035	22,079	22,123	22,167
49 **Agriculture**												
50 Current Price ($/kWh)	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606	$ 0.0606
51 Total Supplied Quantity in N. Caucasus (GWh)	9,881	9,881	9,881	9,881	9,881	9,881	9,881	9,881	9,881	9,881	9,881	9,881
52 Supplied Quantity w/o New Plant (GWh) (less incremental energy)	9,103	9,121	9,140	9,158	9,177	9,195	9,214	9,232	9,251	9,269	9,288	9,306
53 **Transport**												
54 Current Price ($/kWh)	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694	$ 0.0694
55 Total Supplied Quantity in N. Caucasus (GWh)	4,754	4,754	4,754	4,754	4,754	4,754	4,754	4,754	4,754	4,754	4,754	4,754
56 Supplied Quantity w/o New Plant (GWh) (less incremental energy)	4,380	4,389	4,397	4,406	4,415	4,424	4,433	4,442	4,451	4,460	4,469	4,477
57 **Residential**												
58 Current Price ($/kWh)	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196	$ 0.0196
59 Total Supplied Quantity in N. Caucasus (GWh)	19,891	19,891	19,891	19,891	19,891	19,891	19,891	19,891	19,891	19,891	19,891	19,891
60 Supplied Quantity w/o New Plant (GWh) (less incremental energy)	18,325	18,362	18,400	18,437	18,474	18,511	18,548	18,586	18,623	18,660	18,697	18,734
61												
62 **Economic Benefit Calculations -- Outputs**												
63 **Industry**												
64 Economic Benefit of Marginal Power of New Plant ($ million)	128.62	125.56	122.51	119.45	116.39	113.34	110.28	107.22	104.17	101.11	98.05	95.00
65 **Agriculture**												
66 Economic Benefit of Marginal Power of New Plant ($ million)	47.11	45.99	44.87	43.75	42.63	41.51	40.39	39.28	38.16	37.04	35.92	34.80
67 **Transport**												
68 Economic Benefit of Marginal Power of New Plant ($ million)	25.98	25.36	24.75	24.13	23.51	22.89	22.28	21.66	21.04	20.42	19.81	19.19
69 **Residential**												
70 Economic Benefit of Marginal Power of New Plant ($ million)	30.64	29.91	29.19	28.46	27.73	27.00	26.27	25.54	24.82	24.09	23.36	22.63
71												
72 Total Economic Benefit of Marginal Power ($ million)	$232.35	$226.83	$221.31	$215.79	$625.06	$608.02	$590.98	$574.09	$557.27	$540.57	$523.99	$507.46

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	ECONOMIC COST CALCULATIONS ('000 real 1995 US dollars) Project Year	1995 0	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11	2007 12
1	**CAPITAL COSTS**													
2	Power Plant													
3	Western Equipment		19,285	67,134	76,899	58,589	18,312	0	0	0	0	0	0	0
4	Western Indirect		4,323	15,049	17,238	13,134	4,105	0	0	0	0	0	0	0
5	Western Subtotal		23,608	82,183	94,137	71,723	22,417	0	0	0	0	0	0	0
6	Russian Equipment		3,229	11,673	13,867	10,942	3,541	0	0	0	0	0	0	0
7	Russian Materials		2,452	8,885	10,579	8,366	2,907	0	0	0	0	0	0	0
8	Russia Labor		2,979	13,332	18,665	16,807	5,625	0	0	0	0	0	0	0
9	Russian Indirect		2,845	11,698	15,456	13,342	4,660	0	0	0	0	0	0	0
10	Russian Subtotal		11,504	45,588	58,566	49,458	16,733	0	0	0	0	0	0	0
11	Power Plant Total		35,112	127,772	152,703	121,181	39,150	0	0	0	0	0	0	0
12														
13	Transmission Lines													
14	Western Equipment		6,027	8,036	3,014	3,014	0	0	0	0	0	0	0	0
15	Western Indirect		0	0	0	0	0	0	0	0	0	0	0	0
16	Western Subtotal		6,027	8,036	3,014	3,014	0	0	0	0	0	0	0	0
17	Russian Equipment		2,042	2,828	1,100	1,139	0	0	0	0	0	0	0	0
18	Russian Materials		6,428	8,923	3,478	3,610	0	0	0	0	0	0	0	0
19	Russia Labor		5,880	10,080	4,620	5,460	0	0	0	0	0	0	0	0
20	Russian Right-of-Way		1,666	2,623	1,135	1,286	0	0	0	0	0	0	0	0
21	Russian Subtotal		16,016	24,454	10,332	11,495	0	0	0	0	0	0	0	0
22	Transmission Lines Total		22,043	32,490	13,346	14,508	0	0	0	0	0	0	0	0
23														
24	Gas Pipeline													
25	Western Equipment		0	0	0	0	0	0	0	0	0	0	0	0
26	Western Indirect		0	0	0	0	0	0	0	0	0	0	0	0
27	Western Subtotal		0	0	0	0	0	0	0	0	0	0	0	0
28	Russian Equipment		0	0	0	0	0	0	0	0	0	0	0	0
29	Russian Materials		0	0	0	0	0	0	0	0	0	0	0	0
30	Russia Labor		0	0	0	0	0	0	0	0	0	0	0	0
31	Russian Indirect		0	0	0	0	0	0	0	0	0	0	0	0
32	Russian Subtotal		0	0	0	0	0	0	0	0	0	0	0	0
33	Gas Pipeline Total		0	0	0	0	0	0	0	0	0	0	0	0
34														
35	Total Capital Costs		57,155	160,262	166,050	135,689	39,150	0	0	0	0	0	0	0
36														

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ECONOMIC COST CALCULATIONS ('000 real 1995 US dollars)	2008 13	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27
1 **CAPITAL COSTS**															
2 Power Plant															
3 Western Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 Western Indirect	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Western Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Russian Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Russian Materials	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Russia Labor	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Russian Indirect	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 Russian Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Power Plant Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12															
13 Transmission Lines															
14 Western Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 Western Indirect	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16 Western Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 Russian Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 Russian Materials	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19 Russia Labor	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20 Russian Right-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21 Russian Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22 Transmission Lines Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23															
24 Gas Pipeline															
25 Western Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26 Western Indirect	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27 Western Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28 Russian Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29 Russian Materials	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30 Russia Labor	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31 Russian Indirect	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32 Russian Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33 Gas Pipeline Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34															
35 **Total Capital Costs**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36															

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ECONOMIC COST CALCULATIONS ('000 real 1995 US dollars)	2023 28	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39
1 **CAPITAL COSTS**												
2 Power Plant												
3 Western Equipment	0	0	0	0	0	0	0	0	0	0	0	0
4 Western Indirect	0	0	0	0	0	0	0	0	0	0	0	0
5 Western Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
6 Russian Equipment	0	0	0	0	0	0	0	0	0	0	0	0
7 Russian Materials	0	0	0	0	0	0	0	0	0	0	0	0
8 Russia Labor	0	0	0	0	0	0	0	0	0	0	0	0
9 Russian Indirect	0	0	0	0	0	0	0	0	0	0	0	0
10 Russian Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
11 Power Plant Total	0	0	0	0	0	0	0	0	0	0	0	0
12												
13 Transmission Lines												
14 Western Equipment	0	0	0	0	0	0	0	0	0	0	0	0
15 Western Indirect	0	0	0	0	0	0	0	0	0	0	0	0
16 Western Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
17 Russian Equipment	0	0	0	0	0	0	0	0	0	0	0	0
18 Russian Materials	0	0	0	0	0	0	0	0	0	0	0	0
19 Russia Labor	0	0	0	0	0	0	0	0	0	0	0	0
20 Russian Right-of-Way	0	0	0	0	0	0	0	0	0	0	0	0
21 Russian Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
22 Transmission Lines Total	0	0	0	0	0	0	0	0	0	0	0	0
23												
24 Gas Pipeline												
25 Western Equipment	0	0	0	0	0	0	0	0	0	0	0	0
26 Western Indirect	0	0	0	0	0	0	0	0	0	0	0	0
27 Western Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
28 Russian Equipment	0	0	0	0	0	0	0	0	0	0	0	0
29 Russian Materials	0	0	0	0	0	0	0	0	0	0	0	0
30 Russia Labor	0	0	0	0	0	0	0	0	0	0	0	0
31 Russian Indirect	0	0	0	0	0	0	0	0	0	0	0	0
32 Russian Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
33 Gas Pipeline Total	0	0	0	0	0	0	0	0	0	0	0	0
34												
35 Total Capital Costs	0	0	0	0	0	0	0	0	0	0	0	0
36												

ECONOMIC COST CALCULATIONS ('000 real 1995 US dollars)	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Project Year	0	1	2	3	4	5	6	7	8	9	10	11	12
37 **PRODUCTION COSTS**													
38													
39 **Conversion Factors**													
40 **Russian vs. U.S. Costs**													
41 Material	70.0%	73.0%	76.0%	79.0%	82.0%	85.0%	85.5%	86.0%	86.5%	87.0%	87.5%	88.0%	88.5%
42 Equipment	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%	63.0%	66.0%	69.0%	72.0%	75.0%	78.0%	81.0%
43 Labor cost	10.0%	14.0%	18.0%	22.0%	26.0%	30.0%	36.0%	42.0%	48.0%	54.0%	60.0%	62.7%	65.3%
44 Labor productivity factor	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%	62.0%	64.0%	66.0%	68.0%	70.0%	72.0%	74.0%
45 Labor -- Total Cost	20.0%	26.9%	33.3%	39.3%	44.8%	50.0%	58.1%	65.6%	72.7%	79.4%	85.7%	87.0%	88.3%
46 **Russian vs. U.S. Escalation Factors**													
47 Equipment	1.00	1.04	1.08	1.12	1.16	1.20	1.26	1.32	1.38	1.44	1.50	1.56	1.62
48 *Material*	1.00	1.04	1.09	1.13	1.17	1.21	1.22	1.23	1.24	1.24	1.25	1.26	1.26
49 Labor	1.00	1.35	1.67	1.96	2.24	2.50	2.90	3.28	3.64	3.97	4.29	4.35	4.41
50 Average of Labor and Material (O&M, OOPS escalation)	1.00	1.19	1.38	1.55	1.71	1.86	2.06	2.25	2.44	2.61	2.77	2.80	2.84
51 Composite (average of the 3) (escalation for transmission O&M)	1.00	1.14	1.28	1.40	1.52	1.64	1.79	1.94	2.08	2.22	2.35	2.39	2.43
52													
53 **System Generation**													
54 Nominal Capacity (MW) - GT mode, 1st Module		0	0	300	300	0	0	0	0	0	0	0	0
55 Net Rated Capacity - GT mode. 1st Module		0	0	295	295	0	0	0	0	0	0	0	0
56 Nominal Capacity (MW) - GT mode, 2nd Module		0	0	0	300	300	0	0	0	0	0	0	0
57 Net Rated Capacity - GT mode. 2nd Module		0	0	0	295	295	0	0	0	0	0	0	0
58 Nominal Capacity (MW) - CC mode, 1st Module		0	0	0	450	450	450	450	450	450	450	450	450
59 Net Rated Capacity - CC mode, 1st Module		0	0	0	443	443	443	443	443	443	443	443	443
60 Nominal Capacity (MW) - CC mode, 2nd Module		0	0	0	0	450	450	450	450	450	450	450	450
61 Net Rated Capacity - CC mode, 2nd Module		0	0	0	0	443	443	443	443	443	443	443	443
62 Total Nominal Capacity		0	0	300	750	900	900	900	900	900	900	900	900
63 Total Net Rated Capacity		0	0	295	738	886	886	886	886	886	886	886	886
64 Months of Operation - GT mode, 1st Module		0	0	4	8	0	0	0	0	0	0	0	0
65 Months of Operation - GT mode, 2nd Module		0	0	0	10	2	0	0	0	0	0	0	0
66 Months of Operation - CC mode, 1st Module		0	0	0	4	12	12	12	12	12	12	12	12
67 Months of Operation - CC mode, 2nd Module		0	0	0	0	10	12	12	12	12	12	12	12
68 Load Factor - GT mode *		34.8%	34.8%	35.3%	54.1%	27.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
69 Load Factor - CC mode *		90.2%	90.2%	90.2%	90.2%	90.2%	90.2%	90.2%	90.2%	90.2%	90.2%	90.2%	90.2%
70 Operating Hours - GT mode, 1st Module		0	0	1,031	3,160	0	0	0	0	0	0	0	0
71 Operating Hours - GT mode, 2nd Module		0	0	0	3,949	399	0	0	0	0	0	0	0
72 Operating Hours - CC mode, 1st Module		0	0	0	2,634	7,903	7,903	7,903	7,903	7,903	7,903	7,903	7,903
73 Operating Hours - CC mode, 2nd Module		0	0	0	0	6,586	7,903	7,903	7,903	7,903	7,903	7,903	7,903
74 Production (GWh) - GT mode		0	0	309	2,133	120	0	0	0	0	0	0	0
75 Production (GWh) - CC mode		0	0	0	1,185	6,520	7,113	7,113	7,113	7,113	7,113	7,113	7,113
76 Total Production (GWh)		0	0	309	3,318	6,640	7,113	7,113	7,113	7,113	7,113	7,113	7,113
77 Supplied (GWh) - GT mode		0	0	305	2,099	118	0	0	0	0	0	0	0
78 Supplied (GWh) - CC mode		0	0	0	1,167	6,419	7,002	7,002	7,002	7,002	7,002	7,002	7,002
79 Total Supplied (GWh) at the busbar		0	0	305	3,267	6,537	7,002	7,002	7,002	7,002	7,002	7,002	7,002
80													

* Load Factors shown differ from those in the Financial Model. These load factors, for purposes of economic analysis, are based on output figures supplied by the ICF model.

ECONOMIC COST CALCULATIONS ('000 real 1995 US dollars)	2008 13	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27
37 **PRODUCTION COSTS**															
38															
39 **Conversion Factors**															
40 **Russian vs. U.S. Costs**															
41 Material	89.0%	89.5%	90.0%	90.6%	91.3%	91.9%	92.5%	93.1%	93.8%	94.4%	95.0%	95.6%	96.3%	96.9%	97.5%
42 Equipment	84.0%	87.0%	90.0%	90.6%	91.3%	91.9%	92.5%	93.1%	93.8%	94.4%	95.0%	95.6%	96.3%	96.9%	97.5%
43 Labor cost	68.0%	70.7%	73.3%	76.0%	78.7%	81.3%	84.0%	86.7%	89.3%	92.0%	94.7%	97.3%	100.0%	100.0%	100.0%
44 Labor productivity factor	76.0%	78.0%	80.0%	82.0%	84.0%	86.0%	88.0%	90.0%	92.0%	94.0%	96.0%	98.0%	100.0%	100.0%	100.0%
45 Labor -- Total Cost	89.5%	90.6%	91.7%	92.7%	93.7%	94.6%	95.5%	96.3%	97.1%	97.9%	98.6%	99.3%	100.0%	100.0%	100.0%
46 **Russian vs. U.S. Escalation Factors**															
47 Equipment	1.68	1.74	1.80	1.81	1.83	1.84	1.85	1.86	1.88	1.89	1.90	1.91	1.93	1.94	1.95
48 Material	1.27	1.28	1.29	1.29	1.30	1.31	1.32	1.33	1.34	1.35	1.36	1.37	1.38	1.38	1.39
49 Labor	4.47	4.53	4.58	4.63	4.68	4.73	4.77	4.81	4.86	4.89	4.93	4.97	5.00	5.00	5.00
50 Average of Labor and Material (O&M, OOPS escalatio	2.87	2.90	2.93	2.96	2.99	3.02	3.05	3.07	3.10	3.12	3.14	3.17	3.19	3.19	3.20
51 Composite (average of the 3) (escalation for transmiss	2.48	2.52	2.56	2.58	2.60	2.63	2.65	2.67	2.69	2.71	2.73	2.75	2.77	2.77	2.78
52															
53 **System Generation**															
54 Nominal Capacity (MW) - GT mode, 1st Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55 Net Rated Capacity - GT mode. 1st Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
56 Nominal Capacity (MW) - GT mode, 2nd Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
57 Net Rated Capacity - GT mode. 2nd Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
58 Nominal Capacity (MW) - CC mode, 1st Module	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450
59 Net Rated Capacity - CC mode, 1st Module	443	443	443	443	443	443	443	443	443	443	443	443	443	443	443
60 Nominal Capacity (MW) - CC mode, 2nd Module	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450
61 Net Rated Capacity - CC mode, 2nd Module	443	443	443	443	443	443	443	443	443	443	443	443	443	443	443
62 Total Nominal Capacity	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900
63 Total Net Rated Capacity	886	886	886	886	886	886	886	886	886	886	886	886	886	886	886
64 Months of Operation - GT mode, 1st Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
65 Months of Operation - GT mode, 2nd Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
66 Months of Operation - CC mode, 1st Module	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
67 Months of Operation - CC mode, 2nd Module	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
68 Load Factor - GT mode *	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
69 Load Factor - CC mode *	90.2%	90.2%	88.6%	87.0%	85.4%	83.8%	82.2%	80.6%	79.0%	77.3%	75.7%	74.1%	72.5%	70.9%	69.3%
70 Operating Hours - GT mode, 1st Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
71 Operating Hours - GT mode, 2nd Module	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
72 Operating Hours - CC mode, 1st Module	7,903	7,903	7,762	7,621	7,480	7,339	7,198	7,057	6,917	6,776	6,635	6,494	6,353	6,212	6,071
73 Operating Hours - CC mode, 2nd Module	7,903	7,903	7,762	7,621	7,480	7,339	7,198	7,057	6,917	6,776	6,635	6,494	6,353	6,212	6,071
74 Production (GWh) - GT mode	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
75 Production (GWh) - CC mode	7,113	7,113	6,986	6,859	6,732	6,605	6,479	6,352	6,225	6,098	5,971	5,844	5,718	5,591	5,464
76 Total Production (GWh)	7,113	7,113	6,986	6,859	6,732	6,605	6,479	6,352	6,225	6,098	5,971	5,844	5,718	5,591	5,464
77 Supplied (GWh) - GT mode	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
78 Supplied (GWh) - CC mode	7,002	7,002	6,877	6,752	6,627	6,503	6,378	6,253	6,128	6,003	5,878	5,753	5,629	5,504	5,379
79 Total Supplied (GWh) at the busbar	7,002	7,002	6,877	6,752	6,627	6,503	6,378	6,253	6,128	6,003	5,878	5,753	5,629	5,504	5,379
80															

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These load factors, for purposes of economic analysis,
on output figures supplied by the ICF model.

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ECONOMIC COST CALCULATIONS ('000 real 1995 US dollars)	2023 28	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39
37 **PRODUCTION COSTS**												
38												
39 **Conversion Factors**												
40 **Russian vs. U.S. Costs**												
41 Material	98.1%	98.8%	99.4%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
42 Equipment	98.1%	98.8%	99.4%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
43 Labor cost	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
44 Labor productivity factor	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
45 Labor -- Total Cost	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
46 **Russian vs. U.S. Escalation Factors**												
47 Equipment	1.96	1.98	1.99	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
48 Material	1.40	1.41	1.42	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
49 Labor	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
50 Average of Labor and Material (O&M, OOPS escalatio	3.20	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21
51 Composite (average of the 3) (escalation for transmiss	2.79	2.80	2.80	2.81	2.81	2.81	2.81	2.81	2.81	2.81	2.81	2.81
52												
53 **System Generation**												
54 Nominal Capacity (MW) - GT mode, 1st Module	0	0	0	0	0	0	0	0	0	0	0	0
55 Net Rated Capacity - GT mode, 1st Module	0	0	0	0	0	0	0	0	0	0	0	0
56 Nominal Capacity (MW) - GT mode, 2nd Module	0	0	0	0	0	0	0	0	0	0	0	0
57 Net Rated Capacity - GT mode, 2nd Module	0	0	0	0	0	0	0	0	0	0	0	0
58 Nominal Capacity (MW) - CC mode, 1st Module	450	450	450	450	450	450	450	450	450	450	450	450
59 Net Rated Capacity - CC mode, 1st Module	443	443	443	443	443	443	443	443	443	443	443	443
60 Nominal Capacity (MW) - CC mode, 2nd Module	450	450	450	450	450	450	450	450	450	450	450	450
61 Net Rated Capacity - CC mode, 2nd Module	443	443	443	443	443	443	443	443	443	443	443	443
62 Total Nominal Capacity	900	900	900	900	900	900	900	900	900	900	900	900
63 Total Net Rated Capacity	886	886	886	886	886	886	886	886	886	886	886	886
64 Months of Operation - GT mode, 1st Module	0	0	0	0	0	0	0	0	0	0	0	0
65 Months of Operation - GT mode, 2nd Module	0	0	0	0	0	0	0	0	0	0	0	0
66 Months of Operation - CC mode, 1st Module	12	12	12	12	12	12	12	12	12	12	12	12
67 Months of Operation - CC mode, 2nd Module	12	12	12	12	12	12	12	12	12	12	12	12
68 Load Factor - GT mode *	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
69 Load Factor - CC mode *	67.7%	66.1%	64.5%	62.9%	61.3%	59.7%	58.0%	56.4%	54.8%	53.2%	51.6%	50.0%
70 Operating Hours - GT mode, 1st Module	0	0	0	0	0	0	0	0	0	0	0	0
71 Operating Hours - GT mode, 2nd Module	0	0	0	0	0	0	0	0	0	0	0	0
72 Operating Hours - CC mode, 1st Module	5,930	5,789	5,648	5,507	5,366	5,226	5,085	4,944	4,803	4,662	4,521	4,380
73 Operating Hours - CC mode, 2nd Module	5,930	5,789	5,648	5,507	5,366	5,226	5,085	4,944	4,803	4,662	4,521	4,380
74 Production (GWh) - GT mode	0	0	0	0	0	0	0	0	0	0	0	0
75 Production (GWh) - CC mode	5,337	5,210	5,083	4,957	4,830	4,703	4,576	4,449	4,322	4,196	4,069	3,942
76 Total Production (GWh)	5,337	5,210	5,083	4,957	4,830	4,703	4,576	4,449	4,322	4,196	4,069	3,942
77 Supplied (GWh) - GT mode	0	0	0	0	0	0	0	0	0	0	0	0
78 Supplied (GWh) - CC mode	5,254	5,129	5,004	4,880	4,755	4,630	4,505	4,380	4,255	4,130	4,006	3,881
79 Total Supplied (GWh) at the busbar	5,254	5,129	5,004	4,880	4,755	4,630	4,505	4,380	4,255	4,130	4,006	3,881
80												

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	ECONOMIC COST CALCULATIONS ('000 real 1995 US dollars)	Project Year		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
				0	1	2	3	4	5	6	7	8	9	10	11	12
81	**Fuel Consumptions Calculations**	Heat Rate														
82	BTU/kWh - GT mode	10,080			0.00	0.00	3.12	21.50	1.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00
83	BTU/kWh - CC mode	6,771			0.00	0.00	0.00	8.03	44.15	48.16	48.16	48.16	48.16	48.16	48.16	48.16
84	Gas - million MCM				0.000	0.000	0.088	0.837	1.285	1.365	1.365	1.365	1.365	1.365	1.365	1.365
85	Cost (per MCM) real escalation begins 2005			$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.50	$51.01	$51.52
86	Variable Fuel Cost ($/kWh)				$0.0000	$0.0000	$0.0143	$0.0126	$0.0097	$0.0096	$0.0096	$0.0096	$0.0096	$0.0097	$0.0098	$0.0099
87																
88	**O&M Calculations**	Total 1995	$/kW													
89	Fixed O&M Calculations	'000 $	(886 kW)													
90	Non-Russian Materials ($/kW/yr)	$3,550	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068
91	Non-Russian OOPs ($/kW/yr)	$225	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540
92	Russian Materials ($/kW/yr) (escalated)	$360	$0.4063	$0.4063	$0.4237	$0.4411	$0.4586	$0.4760	$0.4934	$0.4963	$0.4992	$0.5021	$0.5050	$0.5079	$0.5108	$0.5137
93	Russian Labor ($/kW/yr) (escalated)	$935	$1.0553	$1.0553	$1.4206	$1.7588	$2.0729	$2.3653	$2.6383	$3.0638	$3.4627	$3.8375	$4.1902	$4.5227	$4.5925	$4.6586
94	Russian OOPs ($/kW/yr) (esc., avg.Mat&Lab)	$405	$0.4571	$0.4571	$0.5460	$0.6291	$0.7069	$0.7800	$0.8489	$0.9427	$1.0307	$1.1135	$1.1916	$1.2652	$1.2820	$1.2979
95	Total Fixed O&M ($/kW/y)	$5,475	$6.1795	$6.1795	$6.6511	$7.0898	$7.4991	$7.8821	$8.2413	$8.7635	$9.2534	$9.7138	$10.1475	$10.5566	$10.6460	$10.7309
96																
97		Total 1995	$/MWh													
98	Variable O&M Calculations *	000 $	(6600 GWh)													
99	Non-Russian Materials ($/kWh)	$3,550	$0.53788	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054
100	Non-Russian OOPs ($/kWh)	$225	$0.03409	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003
101	Russian Materials ($/kWh) (escalated)	$760	$0.11516	$0.00012	$0.00012	$0.00013	$0.00013	$0.00013	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00015
102	Russian Labor ($/kWh) (escalated)	$35	$0.00530	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00002	$0.00002	$0.00002	$0.00002	$0.00002	$0.00002	$0.00002
103	Russian OOPs ($/kWh) (esc., avg.Mat&Lab)	$115	$0.01742	$0.00002	$0.00002	$0.00002	$0.00003	$0.00003	$0.00003	$0.00004	$0.00004	$0.00004	$0.00005	$0.00005	$0.00005	$0.00005
104	Total Variable O&M ($/kWh)	$4,685	$0.70985	$0.00071	$0.00072	$0.00073	$0.00074	$0.00075	$0.00076	$0.00076	$0.00077	$0.00078	$0.00078	$0.00079	$0.00079	$0.00079
105																
106	Total Variable Cost (Fuel & O&M) ($/kWh)			nm	nm	nm	$ 0.015022	$ 0.013356	$ 0.010436	$ 0.010358	$ 0.010364	$ 0.010370	$ 0.010378	$ 0.010477	$ 0.010576	$ 0.010675
107																
108	**Substituted Energy Calculations**															
109	"Average" Marginal Cost of Region w/o Mostovskoy															
110	Marginal Fuel Cost ($/kWh)			$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012211	$ 0.012333	$ 0.012456
111	Marginal Variable O&M Cost ($/kWh) (esc., avg.Mat&Lab)			$ 0.000980	$ 0.001171	$ 0.001349	$ 0.001516	$ 0.001672	$ 0.001820	$ 0.002021	$ 0.002210	$ 0.002387	$ 0.002555	$ 0.002713	$ 0.002748	$ 0.002783
112	Total Marginal Cost w/o Mostovskoy ($/kWh)			$ 0.013070	$ 0.013261	$ 0.013439	$ 0.013606	$ 0.013762	$ 0.013910	$ 0.014111	$ 0.014300	$ 0.014477	$ 0.014645	$ 0.014923	$ 0.015081	$ 0.015239
113	Marginal Cost Savings ($/kWh)			nm	nm	nm	nm	$ 0.000406	$ 0.003474	$ 0.003753	$ 0.003936	$ 0.004107	$ 0.004269	$ 0.004447	$ 0.004506	$ 0.004564
114																
115	**Costs of Production**															
116	Variable O&M				$0	$0	$229	$2,484	$5,029	$5,434	$5,478	$5,519	$5,559	$5,597	$5,610	$5,622
117	Fixed O&M				$0	$0	$2,250	$5,912	$7,417	$7,887	$8,328	$8,742	$9,133	$9,501	$9,581	$9,658
118	Generation Costs				$0	$0	$4,419	$41,834	$64,265	$68,240	$68,240	$68,240	$68,240	$68,922	$69,611	$70,307
119	Transmission O&M ($350,000/yr, escalated by composite)				$0	$0	$0	$533	$573	$628	$680	$729	$776	$821	$836	$852
120	Total Production Costs				0	0	6,898	50,762	77,284	82,189	82,725	83,231	83,708	84,840	85,639	86,439

* Variable O&M figures were available for combined cycle operation only. Previous model runs show separate figures for variable O&M under GT and CC mode. Under these previous runs, data provided showed a lower variable O&M figure per kWh for GT operation than for CC. Accordingly, an assumption that the variable O&M for GT is the same as for CC errs on the side of conservatism.

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ECONOMIC COST CALCULATIONS ('000 real 1995 US dollars)	2008 13	2009 14	2010 15	2011 16	2012 17	2013 18	2014 19	2015 20	2016 21	2017 22	2018 23	2019 24	2020 25	2021 26	2022 27
81 **Fuel Consumptions Calculations**															
82 BTU/kWh - GT mode	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
83 BTU/kWh - CC mode	48.16	48.16	47.30	46.44	45.58	44.73	43.87	43.01	42.15	41.29	40.43	39.57	38.71	37.86	37.00
84 Gas - million MCM	1.365	1.365	1.340	1.316	1.292	1.267	1.243	1.219	1.194	1.170	1.146	1.121	1.097	1.073	1.048
85 Cost (per MCM) real escalation begins 2005	$52.03	$52.55	$53.08	$53.61	$54.14	$54.68	$55.23	$55.78	$56.34	$56.90	$57.47	$58.05	$58.63	$59.22	$59.81
86 Variable Fuel Cost ($/kWh)	$0.0100	$0.0101	$0.0102	$0.0103	$0.0104	$0.0105	$0.0106	$0.0107	$0.0108	$0.0109	$0.0110	$0.0111	$0.0112	$0.0114	$0.0115
87															
88 **O&M Calculations**															
89 Fixed O&M Calculations															
90 Non-Russian Materials ($/kW/yr)	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068
91 Non-Russian OOPs ($/kW/yr)	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540
92 Russian Materials ($/kW/yr) (escalated)	$0.5166	$0.5195	$0.5224	$0.5260	$0.5297	$0.5333	$0.5369	$0.5406	$0.5442	$0.5478	$0.5514	$0.5551	$0.5587	$0.5623	$0.5659
93 Russian Labor ($/kW/yr) (escalated)	$4.7211	$4.7804	$4.8368	$4.8904	$4.9415	$4.9902	$5.0367	$5.0811	$5.1236	$5.1643	$5.2032	$5.2406	$5.2765	$5.2765	$5.2765
94 Russian OOPs ($/kW/yr) (esc., avg.Mat&Lab)	$1.3131	$1.3276	$1.3414	$1.3551	$1.3682	$1.3807	$1.3929	$1.4045	$1.4158	$1.4266	$1.4371	$1.4472	$1.4570	$1.4591	$1.4611
95 Total Fixed O&M ($/kW/y)	$10.8115	$10.8882	$10.9613	$11.0323	$11.1001	$11.1650	$11.2272	$11.2869	$11.3442	$11.3994	$11.4525	$11.5036	$11.5530	$11.5586	$11.5643
96															
97															
98 Variable O&M Calculations *															
99 Non-Russian Materials ($/kWh)	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054
100 Non-Russian OOPs ($/kWh)	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003
101 Russian Materials ($/kWh) (escalated)	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	$0.00016	$0.00016	$0.00016	$0.00016	$0.00016	$0.00016
102 Russian Labor ($/kWh) (escalated)	$0.00002	$0.00002	$0.00002	$0.00002	$0.00002	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003
103 Russian OOPs ($/kWh) (esc., avg.Mat&Lab)	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005	$0.00005	$0.00006	$0.00006	$0.00006	$0.00006
104 Total Variable O&M ($/kWh)	$0.00079	$0.00079	$0.00080	$0.00080	$0.00080	$0.00080	$0.00080	$0.00080	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081
105															
106 Total Variable Cost (Fuel & O&M) ($/kWh)	$ 0.010776	$ 0.010877	$ 0.010980	$ 0.011083	$ 0.011188	$ 0.011294	$ 0.011400	$ 0.011508	$ 0.011617	$ 0.011726	$ 0.011837	$ 0.011949	$ 0.012062	$ 0.012176	$ 0.012290
107															
108 **Substituted Energy Calculations**															
109 "Average" Marginal Cost of Region w/o Mostovskoy															
110 Marginal Fuel Cost ($/kWh)	$ 0.012581	$ 0.012707	$ 0.012834	$ 0.012962	$ 0.013092	$ 0.013223	$ 0.013355	$ 0.013488	$ 0.013623	$ 0.013760	$ 0.013897	$ 0.014036	$ 0.014176	$ 0.014318	$ 0.014461
111 Marginal Variable O&M Cost ($/kWh) (esc., avg.Ma	$ 0.002815	$ 0.002846	$ 0.002876	$ 0.002905	$ 0.002933	$ 0.002960	$ 0.002986	$ 0.003011	$ 0.003035	$ 0.003058	$ 0.003081	$ 0.003103	$ 0.003124	$ 0.003128	$ 0.003133
112 Total Marginal Cost w/o Mostovskoy ($/kWh)	$ 0.015396	$ 0.015553	$ 0.015710	$ 0.015867	$ 0.016025	$ 0.016183	$ 0.016341	$ 0.016500	$ 0.016659	$ 0.016818	$ 0.016978	$ 0.017139	$ 0.017300	$ 0.017446	$ 0.017594
113 Marginal Cost Savings ($/kWh)	$ 0.004620	$ 0.004676	$ 0.004730	$ 0.004784	$ 0.004837	$ 0.004889	$ 0.004941	$ 0.004992	$ 0.005042	$ 0.005092	$ 0.005141	$ 0.005190	$ 0.005238	$ 0.005271	$ 0.005303
114															
115 **Costs of Production**															
116 Variable O&M	$5,634	$5,646	$5,557	$5,469	$5,379	$5,290	$5,199	$5,108	$5,017	$4,925	$4,832	$4,739	$4,645	$4,548	$4,451
117 Fixed O&M	$9,730	$9,799	$9,865	$9,929	$9,990	$10,048	$10,104	$10,158	$10,210	$10,259	$10,307	$10,353	$10,398	$10,403	$10,408
118 Generation Costs	$71,010	$71,720	$71,146	$70,553	$69,941	$69,309	$68,658	$67,987	$67,296	$66,584	$65,852	$65,097	$64,322	$63,524	$62,704
119 Transmission O&M ($350,000/yr, escalated by compo	$866	$881	$895	$903	$911	$919	$927	$934	$941	$948	$955	$962	$968	$971	$973
120 Total Production Costs	87,241	88,047	87,463	86,854	86,222	85,667	84,889	84,188	83,464	82,717	81,946	81,151	80,332	79,445	78,535

* Variable O&M figures were available for combined cy
Previous model runs show separate figures for variable
CC mode. Under these previous runs, data provided s
variable O&M figure per kWh for GT operation than for
an assumption that the variable O&M for GT is the sam
the side of conservatism.

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	ECONOMIC COST CALCULATIONS ('000 real 1995 US dollars)	2023 28	2024 29	2025 30	2026 31	2027 32	2028 33	2029 34	2030 35	2031 36	2032 37	2033 38	2034 39
81	**Fuel Consumptions Calculations**												
82	BTU/kWh - GT mode	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
83	BTU/kWh - CC mode	36.14	35.28	34.42	33.56	32.70	31.84	30.99	30.13	29.27	28.41	27.55	26.69
84	Gas - million MCM	1.024	1.000	0.975	0.951	0.927	0.902	0.878	0.854	0.829	0.805	0.781	0.756
85	Cost (per MCM) real escalation begins 2005	$60.41	$61.01	$61.62	$62.24	$62.86	$63.49	$64.12	$64.76	$65.41	$66.06	$66.73	$67.39
86	Variable Fuel Cost ($/kWh)	$0.0116	$0.0117	$0.0118	$0.0119	$0.0121	$0.0122	$0.0123	$0.0124	$0.0126	$0.0127	$0.0128	$0.0129
87													
88	**O&M Calculations**												
89	Fixed O&M Calculations												
90	Non-Russian Materials ($/kW/yr)	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068
91	Non-Russian OOPs ($/kW/yr)	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540
92	Russian Materials ($/kW/yr) (escalated)	$0.5696	$0.5732	$0.5768	$0.5805	$0.5805	$0.5805	$0.5805	$0.5805	$0.5805	$0.5805	$0.5805	$0.5805
93	Russian Labor ($/kW/yr) (escalated)	$5.2765	$5.2765	$5.2765	$5.2765	$5.2765	$5.2765	$5.2765	$5.2765	$5.2765	$5.2765	$5.2765	$5.2765
94	Russian OOPs ($/kW/yr) (esc., avg.Mat&Lab)	$1.4632	$1.4652	$1.4672	$1.4693	$1.4693	$1.4693	$1.4693	$1.4693	$1.4693	$1.4693	$1.4693	$1.4693
95	Total Fixed O&M ($/kW/y)	$11.5700	$11.5757	$11.5813	$11.5870	$11.5870	$11.5870	$11.5870	$11.5870	$11.5870	$11.5870	$11.5870	$11.5870
96													
97													
98	Variable O&M Calculations *												
99	Non-Russian Materials ($/kWh)	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054
100	Non-Russian OOPs ($/kWh)	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003
101	Russian Materials ($/kWh) (escalated)	$0.00016	$0.00016	$0.00016	$0.00016	$0.00016	$0.00016	$0.00016	$0.00016	$0.00016	$0.00016	$0.00016	$0.00016
102	Russian Labor ($/kWh) (escalated)	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003
103	Russian OOPs ($/kWh) (esc., avg.Mat&Lab)	$0.00006	$0.00006	$0.00006	$0.00006	$0.00006	$0.00006	$0.00006	$0.00006	$0.00006	$0.00006	$0.00006	$0.00006
104	Total Variable O&M ($/kWh)	$0.00082	$0.00082	$0.00082	$0.00082	$0.00082	$0.00082	$0.00082	$0.00082	$0.00082	$0.00082	$0.00082	$0.00082
105													
106	Total Variable Cost (Fuel & O&M) ($/kWh)	$ 0.012406	$ 0.012523	$ 0.012641	$ 0.012761	$ 0.012880	$ 0.013001	$ 0.013123	$ 0.013246	$ 0.013370	$ 0.013496	$ 0.013622	$ 0.013750
107													
108	**Substituted Energy Calculations**												
109	"Average" Marginal Cost of Region w/o Mostovskoy												
110	Marginal Fuel Cost ($/kWh)	$ 0.014606	$ 0.014752	$ 0.014900	$ 0.015049	$ 0.015199	$ 0.015351	$ 0.015505	$ 0.015660	$ 0.015816	$ 0.015974	$ 0.016134	$ 0.016295
111	Marginal Variable O&M Cost ($/kWh) (esc., avg.Ma	$ 0.003137	$ 0.003141	$ 0.003146	$ 0.003150	$ 0.003150	$ 0.003150	$ 0.003150	$ 0.003150	$ 0.003150	$ 0.003150	$ 0.003150	$ 0.003150
112	Total Marginal Cost w/o Mostovskoy ($/kWh)	$ 0.017743	$ 0.017893	$ 0.018045	$ 0.018199	$ 0.018349	$ 0.018501	$ 0.018655	$ 0.018810	$ 0.018966	$ 0.019124	$ 0.019284	$ 0.019445
113	Marginal Cost Savings ($/kWh)	$ 0.005337	$ 0.005370	$ 0.005404	$ 0.005438	$ 0.005469	$ 0.005500	$ 0.005532	$ 0.005564	$ 0.005596	$ 0.005629	$ 0.005662	$ 0.005695
114													
115	**Costs of Production**												
116	Variable O&M	$4,353	$4,256	$4,158	$4,059	$3,956	$3,852	$3,748	$3,644	$3,540	$3,436	$3,332	$3,228
117	Fixed O&M	$10,413	$10,418	$10,423	$10,428	$10,428	$10,428	$10,428	$10,428	$10,428	$10,428	$10,428	$10,428
118	Generation Costs	$61,861	$60,994	$60,105	$59,191	$58,253	$57,291	$56,303	$55,290	$54,252	$53,186	$52,094	$50,975
119	Transmission O&M ($350,000/yr, escalated by compo	$976	$978	$981	$983	$983	$983	$983	$983	$983	$983	$983	$983
120	Total Production Costs	77,603	76,647	75,667	74,662	73,621	72,554	71,463	70,346	69,203	68,034	66,838	65,615

* Variable O&M figures were available for combined cy
Previous model runs show separate figures for variable
CC mode. Under these previous runs, data provided s
variable O&M figure per kWh for GT operation than for
an assumption that the variable O&M for GT is the sam
the side of conservatism.

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ECONOMIC CAPITAL COST CALCULATIONS

		Russian					Non-Russian			
1	**Base Project Cost**									
2	'000 1995 US dollars	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
3	Civil Works	0	9,092	7,883	0	16,975	0	0	0	16,975
4	Combustion Turbine	0	0	440	0	440	120,000	0	120,000	120,440
5	HRSG	0	0	1,760	0	1,760	34,500	0	34,500	36,260
6	Steam Turbines	0	0	165	0	165	27,000	0	27,000	27,165
7	Distributed Control System	0	0	0	0	0	2,900	0	2,900	2,900
8	Mechanical Package	20,496	11,205	5,137	0	36,838	26,000	0	26,000	62,838
9	Electrical Package	14,980	7,545	4,718	0	27,243	0	0	0	27,243
10	Switchyard	3,200	1,440	6,400	0	11,040	29,818	0	29,818	40,858
11	Engineering & Project Mgmt.	0	0	0	29,010	29,010	0	53,850	53,850	82,860
12	Subtotal Generation Plant	38,676	29,282	26,503	29,010	123,471	240,218	53,850	294,068	417,539
13	Transmission Line	6,545	20,545	14,000	4,545	45,636	20,091	0	20,091	65,727
14	Gas Pipeline	0	0	9,400	3,500	12,900	25,100	0	25,100	38,000
15	Total Project Costs	45,221	49,827	49,903	37,055	182,007	285,409	53,850	339,259	521,266
16										

		Russian				Non-Russian	
17	**Scenario Matrix**						
18	Is each component part of project cost?	Equipment	Material	Labor	Indirect	Equipment	Indirect
19	Civil Works	yes	yes	yes	yes	yes	yes
20	Combustion Turbine	yes	yes	yes	yes	yes	yes
21	HRSG	yes	yes	yes	yes	yes	yes
22	Steam Turbines	yes	yes	yes	yes	yes	yes
23	Distributed Control System	yes	yes	yes	yes	yes	yes
24	Mechanical Package	yes	yes	yes	yes	yes	yes
25	Electrical Package	yes	yes	yes	yes	yes	yes
26	Switchyard	yes	yes	yes	yes	yes	yes
27	Engineering & Project Mgmt.	yes	yes	yes	yes	yes	yes
28	Transmission Line	yes	yes	yes	yes	yes	yes
29	Gas Pipeline	no	no	no	no	no	no
30							

		Russian					Non-Russian			
31	**Base Project Scenario**									
32	'000 1995 US dollars	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
33	Civil Works	0	9,092	7,883	0	16,975	0	0	0	16,975
34	Combustion Turbine	0	0	440	0	440	120,000	0	120,000	120,440
35	HRSG	0	0	1,760	0	1,760	34,500	0	34,500	36,260
36	Steam Turbines	0	0	165	0	165	27,000	0	27,000	27,165
37	Distributed Control System	0	0	0	0	0	2,900	0	2,900	2,900
38	Mechanical Package	20,496	11,205	5,137	0	36,838	26,000	0	26,000	62,838
39	Electrical Package	14,980	7,545	4,718	0	27,243	0	0	0	27,243
40	Switchyard	3,200	1,440	6,400	0	11,040	29,818	0	29,818	40,858
41	Engineering & Project Mgmt.	0	0	0	29,010	29,010	0	53,850	53,850	82,860
42	Subtotal Generation Plant	38,676	29,282	26,503	29,010	123,471	240,218	53,850	294,068	417,539
43	Transmission Line	6,545	20,545	14,000	4,545	45,636	20,091	0	20,091	65,727
44	Gas Pipeline	0	0	0	0	0	0	0	0	0
45	Total Project Costs	45,221	49,827	40,503	33,555	169,107	260,309	53,850	314,159	483,266
46										

ECONOMIC CAPITAL COST CALCULATIONS

47		
48	**Duties & Taxes =**	**20%**
49		

	Duties & Taxes, Matrix	Russian				Non-Russian	
51	Do duties/taxes apply to each component?	Equipment	Material	Labor	Indirect	Equipment	Indirect
52	Civil Works	no	no	no	no	no	no
53	*Combustion Turbine*	*no*	*no*	*no*	*no*	*no*	*no*
54	HRSG	no	no	no	no	no	no
55	Steam Turbines	no	no	no	no	no	no
56	Distributed Control System	no	no	no	no	no	no
57	Mechanical Package	no	no	no	no	no	no
58	Electrical Package	no	no	no	no	no	no
59	Switchyard	no	no	no	no	no	no
60	Engineering & Project Mgmt.	no	no	no	no	no	no
61	Transmission Line	no	no	no	no	no	no
62	*Gas Pipeline*	*no*	*no*	*no*	*no*	*no*	*no*

63

64

65	**Duties & Taxes, Calculated**	Russian					Non-Russian			
66	'000 1995 US dollars	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
67	Civil Works	0	0	0	0	0	0	0	0	0
68	Combustion Turbine	0	0	0	0	0	0	0	0	0
69	HRSG	0	0	0	0	0	0	0	0	0
70	Steam Turbines	0	0	0	0	0	0	0	0	0
71	Distributed Control System	0	0	0	0	0	0	0	0	0
72	Mechanical Package	0	0	0	0	0	0	0	0	0
73	Electrical Package	0	0	0	0	0	0	0	0	0
74	Switchyard	0	0	0	0	0	0	0	0	0
75	Engineering & Project Mgmt.	0	0	0	0	0	0	0	0	0
76	*Subtotal Generation Plant*	0	0	0	0	0	0	0	0	0
77	Transmission Line	0	0	0	0	0	0	0	0	0
78	Gas Pipeline	0	0	0	0	0	0	0	0	0
79	Total Project Duties & Taxes	0	0	0	0	0	0	0	0	0

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ECONOMIC CAPITAL COST CALCULATIONS

81					
82	**Physical Contingencies**	25%	Russian	10%	Non-Russian
83					

		Russian				Non-Russian	
84	**Contingencies, Matrix**						
85	Do contengencies apply to each component?	Equipment	Material	Labor	Indirect	Equipment	Indirect
86	Civil Works	no	no	no	no	no	no
87	Combustion Turbine	no	no	no	no	no	no
88	HRSG	no	no	no	no	no	no
89	Steam Turbines	no	no	no	no	no	no
90	Distributed Control System	no	no	no	no	no	no
91	Mechanical Package	no	no	no	no	no	no
92	Electrical Package	no	no	no	no	no	no
93	Switchyard	no	no	no	no	no	no
94	Engineering & Project Mgmt.	no	no	no	no	no	no
95	Transmission Line	no	no	no	no	no	no
96	Gas Pipeline	no	no	no	no	no	no
97							
98							

		Russian					Non-Russian			
99	**Contingencies, Calculated**									
100	'000 1995 US dollars	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
101	Civil Works	0	0	0	0	0	0	0	0	0
102	Combustion Turbine	0	0	0	0	0	0	0	0	0
103	HRSG	0	0	0	0	0	0	0	0	0
104	Steam Turbines	0	0	0	0	0	0	0	0	0
105	Distributed Control System	0	0	0	0	0	0	0	0	0
106	Mechanical Package	0	0	0	0	0	0	0	0	0
107	Electrical Package	0	0	0	0	0	0	0	0	0
108	Switchyard	0	0	0	0	0	0	0	0	0
109	Engineering & Project Mgmt.	0	0	0	0	0	0	0	0	0
110	Subtotal Generation Plant	0	0	0	0	0	0	0	0	0
111	Transmission Line	0	0	0	0	0	0	0	0	0
112	Gas Pipeline	0	0	0	0	0	0	0	0	0
113	Total Physical Contingencies	0	0	0	0	0	0	0	0	0
114										

ECONOMIC CAPITAL COST CALCULATIONS

Expenditure Profile	Project Year					
	1	2	3	4	5	Total
Civil Works	8%	28%	32%	24%	8%	100%
Combustion Turbine	8%	28%	32%	24%	8%	100%
HRSG	8%	28%	32%	24%	8%	100%
Steam Turbines	8%	28%	32%	24%	8%	100%
Distributed Control System	8%	28%	32%	24%	8%	100%
Mechanical Package	8%	28%	32%	24%	8%	100%
Electrical Package	8%	28%	32%	24%	8%	100%
Switchyard	8%	28%	32%	24%	8%	100%
Engineering & Project Mgmt.	8%	28%	32%	24%	8%	100%
Transmission Line	30%	40%	15%	15%	0%	100%
Gas Pipeline	40%	60%	0%	0%	0%	100%

Escalation Matrix	Russian vs. U.S. Real Escalation			
Is each component to be escalated?	Equipment	Material	Labor	Indirect
Civil Works	yes	yes	yes	yes
Combustion Turbine	yes	yes	yes	yes
HRSG	yes	yes	yes	yes
Steam Turbines	yes	yes	yes	yes
Distributed Control System	yes	yes	yes	yes
Mechanical Package	yes	yes	yes	yes
Electrical Package	yes	yes	yes	yes
Switchyard	yes	yes	yes	yes
Engineering & Project Mgmt.	yes	yes	yes	yes
Transmission Line	yes	yes	yes	yes
Gas Pipeline	yes	yes	yes	yes

Real Escalation Factors	Project Year					
	0	1	2	3	4	5
RUSSIAN VS. U.S. COSTS						
Material	70.0%	73.0%	76.0%	79.0%	82.0%	85.0%
Equipment	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%
Labor	10.0%	14.0%	18.0%	22.0%	26.0%	30.0%
Labor productivity	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%
Labor -- total cost	20.0%	26.9%	33.3%	39.3%	44.8%	50.0%
RUSSIAN VS. U.S. ESCALATION FACTORS						
Equipment	1.00	1.04	1.08	1.12	1.16	1.20
Material	1.00	1.04	1.09	1.13	1.17	1.21
Labor	1.00	1.40	1.80	2.20	2.60	3.00
Average of Labor & Material (Indirect)	1.00	1.22	1.44	1.66	1.89	2.11

ECONOMIC CAPITAL COST CALCULATIONS

160										
161	**Full Project Costs**	Year 1								
162	Includes real escalation	Russian					Non-Russian			
163		Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
164	Civil Works	0	761	886	0	1,647	0	0	0	1,647
165	Combustion Turbine	0	0	49	0	49	9,634	0	9,634	9,683
166	HRSG	0	0	198	0	198	2,770	0	2,770	2,967
167	Steam Turbines	0	0	19	0	19	2,168	0	2,168	2,186
168	Distributed Control System	0	0	0	0	0	233	0	233	233
169	Mechanical Package	1,711	938	577	0	3,227	2,087	0	2,087	5,314
170	Electrical Package	1,251	632	530	0	2,413	0	0	0	2,413
171	Switchyard	267	121	719	0	1,107	2,394	0	2,394	3,501
172	Engineering & Project Mgmt.	0	0	0	2,845	2,845	0	4,323	4,323	7,168
173	Subtotal Generation Plant	3,229	2,452	2,979	2,845	11,504	19,285	4,323	23,608	35,112
174	Transmission Line	2,042	6,428	5,880	1,666	16,016	6,027	0	6,027	22,043
175	Gas Pipeline	0	0	0	0	0	0	0	0	0
176	Total Project Costs	5,271	8,879	8,859	4,510	27,520	25,312	4,323	29,635	57,155
177	**Full Project Costs**	Year 2								
178	Includes real escalation	Russian					Non-Russian			
179		Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
180	Civil Works	0	2,759	3,966	0	6,724	0	0	0	6,724
181	Combustion Turbine	0	0	221	0	221	33,536	0	33,536	33,758
182	HRSG	0	0	885	0	885	9,642	0	9,642	10,527
183	Steam Turbines	0	0	83	0	83	7,546	0	7,546	7,629
184	Distributed Control System	0	0	0	0	0	810	0	810	810
185	Mechanical Package	6,186	3,400	2,584	0	12,170	7,266	0	7,266	19,436
186	Electrical Package	4,521	2,289	2,373	0	9,184	0	0	0	9,184
187	Switchyard	966	437	3,219	0	4,622	8,333	0	8,333	12,956
188	Engineering & Project Mgmt.	0	0	0	11,698	11,698	0	15,049	15,049	26,747
189	Subtotal Generation Plant	11,673	8,885	13,332	11,698	45,588	67,134	15,049	82,183	127,772
190	Transmission Line	2,828	8,923	10,080	2,623	24,454	8,036	0	8,036	32,490
191	Gas Pipeline	0	0	0	0	0	0	0	0	0
192	Total Project Costs	14,501	17,807	23,412	14,321	70,042	75,170	15,049	90,220	160,262

ECONOMIC CAPITAL COST CALCULATIONS

		Year 3								
193	**Full Project Costs**									
194	Includes real escalation	Russian					Non-Russian			
195		Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
196	Civil Works	0	3,285	5,552	0	8,836	0	0	0	8,836
197	Combustion Turbine	0	0	310	0	310	38,414	0	38,414	38,724
198	HRSG	0	0	1,240	0	1,240	11,044	0	11,044	12,284
199	Steam Turbines	0	0	116	0	116	8,643	0	8,643	8,759
200	Distributed Control System	0	0	0	0	0	928	0	928	928
201	Mechanical Package	7,349	4,048	3,618	0	15,014	8,323	0	8,323	23,338
202	Electrical Package	5,371	2,726	3,323	0	11,419	0	0	0	11,419
203	Switchyard	1,147	520	4,507	0	6,175	9,545	0	9,545	15,720
204	Engineering & Project Mgmt.	0	0	0	15,456	15,456	0	17,238	17,238	32,694
205	Subtotal Generation Plant	13,867	10,579	18,665	15,456	58,566	76,899	17,238	94,137	152,703
206	Transmission Line	1,100	3,478	4,620	1,135	10,332	3,014	0	3,014	13,346
207	Gas Pipeline	0	0	0	0	0	0	0	0	0
208	Total Project Costs	14,966	14,057	23,285	16,590	68,899	79,912	17,238	97,151	166,050

		Year 4								
209	**Full Project Costs**									
210	Includes real escalation	Russian					Non-Russian			
211		Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
212	Civil Works	0	2,598	4,999	0	7,597	0	0	0	7,597
213	Combustion Turbine	0	0	279	0	279	29,268	0	29,268	29,547
214	HRSG	0	0	1,116	0	1,116	8,415	0	8,415	9,531
215	Steam Turbines	0	0	105	0	105	6,585	0	6,585	6,690
216	Distributed Control System	0	0	0	0	0	707	0	707	707
217	Mechanical Package	5,799	3,201	3,258	0	12,258	6,341	0	6,341	18,599
218	Electrical Package	4,238	2,156	2,992	0	9,386	0	0	0	9,386
219	Switchyard	905	411	4,058	0	5,375	7,273	0	7,273	12,648
220	Engineering & Project Mgmt.	0	0	0	13,342	13,342	0	13,134	13,134	26,476
221	Subtotal Generation Plant	10,942	8,366	16,807	13,342	49,458	58,589	13,134	71,723	121,181
222	Transmission Line	1,139	3,610	5,460	1,286	11,495	3,014	0	3,014	14,508
223	Gas Pipeline	0	0	0	0	0	0	0	0	0
224	Total Project Costs	12,081	11,976	22,267	14,628	60,952	61,603	13,134	74,737	135,689

ECONOMIC CAPITAL COST CALCULATIONS

225	**Full Project Costs**	Year 5								
226	Includes real escalation	Russian					Non-Russian			
227		Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
228	Civil Works	0	842	1,803	0	2,644	0	0	0	2,644
229	Combustion Turbine	0	0	101	0	101	9,148	0	9,148	9,248
230	HRSG	0	0	402	0	402	2,630	0	2,630	3,032
231	Steam Turbines	0	0	38	0	38	2,058	0	2,058	2,096
232	Distributed Control System	0	0	0	0	0	221	0	221	221
233	Mechanical Package	1,875	1,037	1,175	0	4,087	1,982	0	1,982	6,069
234	Electrical Package	1,370	698	1,079	0	3,148	0	0	0	3,148
235	Switchyard	296	329	1,028	0	1,654	2,273	0	2,273	3,927
236	Engineering & Project Mgmt.	0	0	0	4,660	4,660	0	4,105	4,105	8,765
237	Subtotal Generation Plant	3,541	2,907	5,625	4,660	16,733	18,312	4,105	22,417	39,150
238	Transmission Line	0	0	0	0	0	0	0	0	0
239	Gas Pipeline	0	0	0	0	0	0	0	0	0
240	Total Project Costs	3,541	2,907	5,625	4,660	16,733	18,312	4,105	22,417	39,150
241	**Full Project Costs**	Total of 5 Years								
242	Includes real escalation	Russian					Non-Russian			
243		Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
244	Civil Works	0	10,244	17,205	0	27,449	0	0	0	27,449
245	Combustion Turbine	0	0	960	0	960	120,000	0	120,000	120,960
246	HRSG	0	0	3,841	0	3,841	34,500	0	34,500	38,341
247	Steam Turbines	0	0	360	0	360	27,000	0	27,000	27,360
248	Distributed Control System	0	0	0	0	0	2,900	0	2,900	2,900
249	Mechanical Package	22,920	12,625	11,212	0	46,756	26,000	0	26,000	72,756
250	Electrical Package	16,751	8,501	10,297	0	35,550	0	0	0	35,550
251	Switchyard	3,582	1,818	13,533	0	18,933	29,818	0	29,818	48,751
252	Engineering & Project Mgmt.	0	0	0	48,000	48,000	0	53,850	53,850	101,850
253	Subtotal Generation Plant	43,253	33,188	57,408	48,000	181,850	240,218	53,850	294,068	475,918
254	Transmission Line	7,108	22,439	26,040	6,709	62,296	20,091	0	20,091	82,387
255	Gas Pipeline	0	0	0	0	0	0	0	0	0
256	Total Project Costs	50,361	55,627	83,448	54,710	244,146	260,309	53,850	314,159	558,305

APPENDIX B.2 – SENSITIVITY RUN SCENARIOS

CONTENTS

SCENARIO: BASE CASE

ECONOMIC RATE OF RETURN	**20.2%**
Net Present Value at 15% Discount Rate (1995 US $ '000)	$191,358

ECONOMIC BENEFIT SUMMARY	1996-1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Quantity of Substituted Energy (GWh)	0	0	1,914	3,904	3,638	3,173	2,247	1,068	372	299	226	151
Quantity of Incremental Energy (GWh)	0	265	1,177	2,291	2,927	3,331	4,137	5,163	5,768	5,832	5,895	5,960
Energy Lost in Transmission/Distribution (GWh)	0	40	176	342	437	498	618	771	862	871	881	891
Total Energy Supplied (GWh)	0	305	3,267	6,537	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002
Benefit of Substituted Energy (1995 US $ '000)	$0	$0	$777	$13,561	$13,654	$12,488	$9,229	$4,559	$1,654	$1,347	$1,032	$698
Benefit of Incremental Energy (1995 US $ '000)	0	12,866	57,571	112,708	144,459	164,911	205,759	257,947	289,556	293,481	297,422	301,467
Total Benefit of Energy Supplied (1995 US $ '000)	$0	$12,866	$58,348	$126,269	$158,113	$177,399	$214,988	$262,506	$291,210	$294,828	$298,454	$302,165
ECONOMIC COST SUMMARY												
Total Capital Costs	$217,416	$166,050	$135,689	$39,150	$0	$0	$0	$0	$0	$0	$0	$0
Total Production Costs	0	6,898	50,762	77,284	82,189	82,725	83,231	83,708	84,840	85,639	86,439	87,241
Total Costs	$217,416	$172,947	$186,451	$116,434	$82,189	$82,725	$83,231	$83,708	$84,840	$85,639	$86,439	$87,241
ANNUAL NET BENEFIT	($217,416)	($160,081)	($128,103)	$9,835	$75,925	$94,673	$131,758	$178,799	$206,370	$209,190	$212,015	$214,924

OVERVIEW OF CASE ASSUMPTIONS

- September 1995 tariffs applied in benefit calculations throughout life of project.
- No consumer surplus calculated in benefit calculations.
- Base case assumptions from ICF model: a) total output, b) portion which is substituted energy, c) portion which is incremental energy.

SCENARIO: CASE 2.A -- CAPITAL COST OVERRUNS EQUAL TO FINANCIAL PHYSICAL CONTINGENCIES

ECONOMIC RATE OF RETURN	18.5%
Net Present Value at 15% Discount Rate (1995 US $ '000)	$142,353

	1996-1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
ECONOMIC BENEFIT SUMMARY												
Quantity of Substituted Energy (GWh)	0	0	1,914	3,904	3,638	3,173	2,247	1,068	372	299	226	151
Quantity of Incremental Energy (GWh)	0	265	1,177	2,291	2,927	3,331	4,137	5,163	5,768	5,832	5,895	5,960
Energy Lost in Transmission/Distribution (GWh)	0	40	176	342	437	498	618	771	862	871	881	891
Total Energy Supplied (GWh)	0	305	3,267	6,537	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002
Benefit of Substituted Energy (1995 US $ '000)	$0	$0	$777	$13,561	$13,654	$12,488	$9,229	$4,559	$1,654	$1,347	$1,032	$698
Benefit of Incremental Energy (1995 US $ '000)	0	12,866	57,571	112,708	144,459	164,911	205,759	257,947	289,556	293,481	297,422	301,467
Total Benefit of Energy Supplied (1995 US $ '000)	$0	$12,866	$58,348	$126,269	$158,113	$177,399	$214,988	$262,506	$291,210	$294,828	$298,454	$302,165
ECONOMIC COST SUMMARY												
Total Capital Costs	$248,665	$186,086	$151,542	$43,334	$0	$0	$0	$0	$0	$0	$0	$0
Total Production Costs	0	6,898	50,762	77,284	82,189	82,725	83,231	83,708	84,840	85,639	86,439	87,241
Total Costs	$248,665	$192,983	$202,304	$120,618	$82,189	$82,725	$83,231	$83,708	$84,840	$85,639	$86,439	$87,241
ANNUAL NET BENEFIT	($248,665)	($180,117)	($143,956)	$5,651	$75,925	$94,673	$131,758	$178,799	$206,370	$209,190	$212,015	$214,924

OVERVIEW OF CASE ASSUMPTIONS

- Capital cost overruns equal to physical contingencies: $71.3 million overrun (25% of Russian items, 10% of Non-Russian items).
- September 1995 tariffs applied in benefit calculations throughout life of project.
- No consumer surplus calculated in benefit calculations.
- Base case assumptions from ICF model: a) total output, b) portion which is substituted energy, c) portion which is incremental energy.

ECONOMIC CAPITAL COST CALCULATIONS

115		6.29%	21.90%	25.08%	19.11%	27.62%	100.00%
116	**Expenditure Profile**	Project Year					
117		1	2	3	4	5	Total
118	Civil Works	8%	28%	32%	24%	8%	100%
119	Combustion Turbine	8%	28%	32%	24%	8%	100%
120	HRSG	8%	28%	32%	24%	8%	100%
121	Steam Turbines	8%	28%	32%	24%	8%	100%
122	Distributed Control System	8%	28%	32%	24%	8%	100%
123	Mechanical Package	8%	28%	32%	24%	8%	100%
124	Electrical Package	8%	28%	32%	24%	8%	100%
125	Switchyard	8%	28%	32%	24%	8%	100%
126	Engineering & Project Mgmt.	8%	28%	32%	24%	8%	100%
127	Transmission Line	30%	40%	15%	15%	0%	100%
128	Gas Pipeline	40%	60%	0%	0%	0%	100%
129							
130							

131	**Escalation Matrix**	Russian vs. U.S. Real Escalation			
132	Is each component to be escalated?	Equipment	Material	Labor	Indirect
133	Civil Works	yes	yes	yes	yes
134	Combustion Turbine	yes	yes	yes	yes
135	HRSG	yes	yes	yes	yes
136	Steam Turbines	yes	yes	yes	yes
137	Distributed Control System	yes	yes	yes	yes
138	Mechanical Package	yes	yes	yes	yes
139	Electrical Package	yes	yes	yes	yes
140	Switchyard	yes	yes	yes	yes
141	Engineering & Project Mgmt.	yes	yes	yes	yes
142	Transmission Line	yes	yes	yes	yes
143	Gas Pipeline	yes	yes	yes	yes
144					
145					

146	**Real Escalation Factors**	Project Year					
147		0	1	2	3	4	5
148	RUSSIAN VS. U.S. COSTS						
149	Material	70.0%	73.0%	76.0%	79.0%	82.0%	85.0%
150	Equipment	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%
151	Labor	10.0%	14.0%	18.0%	22.0%	26.0%	30.0%
152	Labor productivity	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%
153	Labor -- total cost	20.0%	26.9%	33.3%	39.3%	44.8%	50.0%
154	RUSSIAN VS. U.S. ESCALATION FACTORS						
155	Equipment	1.00	1.04	1.08	1.12	1.16	1.20
156	Material	1.00	1.04	1.09	1.13	1.17	1.21
157	Labor	1.00	1.40	1.80	2.20	2.60	3.00
158	Average of Labor & Material (Indirect)	1.00	1.22	1.44	1.66	1.89	2.11
159							

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SCENARIO: CASE 2.B – MAXIMUM CAPITAL COST OVERRUNS TO YIELD EIRR OF 15%

ECONOMIC RATE OF RETURN	15.0%
Net Present Value at 15% Discount Rate (1995 US $ '000)	$0

	1996-1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
ECONOMIC BENEFIT SUMMARY												
Quantity of Substituted Energy (GWh)	0	0	1,914	3,904	3,638	3,173	2,247	1,068	372	299	226	151
Quantity of Incremental Energy (GWh)	0	265	1,177	2,291	2,927	3,331	4,137	5,163	5,768	5,832	5,895	5,960
Energy Lost in Transmission/Distribution (GWh)	0	40	176	342	437	498	618	771	862	871	881	891
Total Energy Supplied (GWh)	0	305	3,267	6,537	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002
Benefit of Substituted Energy (1995 US $ '000)	$0	$0	$777	$13,561	$13,654	$12,488	$9,229	$4,559	$1,654	$1,347	$1,032	$698
Benefit of Incremental Energy (1995 US $ '000)	0	12,866	57,571	112,708	144,459	164,911	205,759	257,947	289,556	293,481	297,422	301,467
Total Benefit of Energy Supplied (1995 US $ '000)	$0	$12,866	$58,348	$126,269	$158,113	$177,399	$214,988	$262,506	$291,210	$294,828	$298,454	$302,165
ECONOMIC COST SUMMARY												
Total Capital Costs	$339,438	$244,287	$197,590	$55,489	$0	$0	$0	$0	$0	$0	$0	$0
Total Production Costs	0	6,898	50,762	77,284	82,189	82,725	83,231	83,708	84,840	85,639	86,439	87,241
Total Costs	$339,438	$251,185	$248,352	$132,773	$82,189	$82,725	$83,231	$83,708	$84,840	$85,639	$86,439	$87,241
ANNUAL NET BENEFIT	($339,438)	($238,319)	($190,004)	($6,504)	$75,925	$94,673	$131,758	$178,799	$206,370	$209,190	$212,015	$214,924

OVERVIEW OF CASE ASSUMPTIONS

- Maximum tolerable capital cost overruns so that EIRR equals 15%: $278.5 million overun (98% of Russian items, 39% of Non-Russian items).
- September 1995 tariffs applied in benefit calculations throughout life of project.
- No consumer surplus calculated in benefit calculations.
- Base case assumptions from ICF model: a) total output, b) portion which is substituted energy, c) portion which is incremental energy.

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ECONOMIC CAPITAL COST CALCULATIONS

81					
82	**Physical Contingencies**	98%	Russian	39%	Non-Russian
83					

84	**Contingencies, Matrix**	Russian				Non-Russian	
85	Do contengencies apply to each component?	Equipment	Material	Labor	Indirect	Equipment	Indirect
86	Civil Works	yes	yes	yes	yes	yes	yes
87	Combustion Turbine	yes	yes	yes	yes	yes	yes
88	HRSG	yes	yes	yes	yes	yes	yes
89	Steam Turbines	yes	yes	yes	yes	yes	yes
90	Distributed Control System	yes	yes	yes	yes	yes	yes
91	Mechanical Package	yes	yes	yes	yes	yes	yes
92	Electrical Package	yes	yes	yes	yes	yes	yes
93	Switchyard	yes	yes	yes	yes	yes	yes
94	Engineering & Project Mgmt.	yes	yes	yes	yes	yes	yes
95	Transmission Line	yes	yes	yes	yes	yes	yes
96	Gas Pipeline	yes	yes	yes	yes	yes	yes
97							
98							

99	**Contingencies, Calculated**	Russian					Non-Russian			
100	'000 1995 US dollars	Equipment	Material	Labor	Indirect	Subtotal	Equipment	Indirect	Subtotal	Total
101	Civil Works	0	8,876	7,695	0	16,571	0	0	0	16,571
102	Combustion Turbine	0	0	430	0	430	46,858	0	46,858	47,288
103	HRSG	0	0	1,718	0	1,718	13,472	0	13,472	15,190
104	Steam Turbines	0	0	161	0	161	10,543	0	10,543	10,704
105	Distributed Control System	0	0	0	0	0	1,132	0	1,132	1,132
106	Mechanical Package	20,008	10,938	5,015	0	35,962	10,153	0	10,153	46,114
107	Electrical Package	14,624	7,366	4,606	0	26,595	0	0	0	26,595
108	Switchyard	3,124	1,406	6,248	0	10,777	11,643	0	11,643	22,421
109	Engineering & Project Mgmt.	0	0	0	28,320	28,320	0	0	0	28,320
110	Subtotal Generation Plant	37,756	28,585	25,873	28,320	120,534	93,802	0	93,802	214,335
111	Transmission Line	6,390	20,057	13,667	4,437	44,551	19,613	0	19,613	64,164
112	Gas Pipeline	0	0	0	0	0	0	0	0	0
113	Total Physical Contingencies	44,146	48,642	39,540	32,757	165,085	113,415	0	113,415	278,499
114										

SCENARIO: BASE CASE

ECONOMIC RATE OF RETURN	20.0%
Net Present Value at 15% Discount Rate (1995 US $ '000)	$185,399

	1996-1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
ECONOMIC BENEFIT SUMMARY												
Quantity of Substituted Energy (GWh)	0	0	0	0	3,055	3,173	2,247	1,068	372	299	226	151
Quantity of Incremental Energy (GWh)	0	0	406	1,528	2,927	3,331	4,137	5,163	5,768	5,832	5,895	5,960
Energy Lost in Transmission/Distribution (GWh)	0	0	61	228	437	498	618	771	862	871	881	891
Total Energy Supplied (GWh)	0	0	467	1,757	6,419	7,002	7,002	7,002	7,002	7,002	7,002	7,002
Benefit of Substituted Energy (1995 US $ '000)	$0	$0	$0	$0	$11,464	$12,488	$9,229	$4,559	$1,654	$1,347	$1,032	$698
Benefit of Incremental Energy (1995 US $ '000)	0	0	19,852	75,204	144,459	164,911	205,759	257,947	289,556	293,481	297,422	301,467
Total Benefit of Energy Supplied (1995 US $ '000)	$0	$0	$19,852	$75,204	$155,923	$177,399	$214,988	$262,506	$291,210	$294,828	$298,454	$302,165
ECONOMIC COST SUMMARY												
Total Capital Costs	$217,416	$166,050	$135,689	$39,150	$0	$0	$0	$0	$0	$0	$0	$0
Total Production Costs	0	2,250	13,569	29,273	76,049	82,725	83,231	83,708	84,840	85,639	86,439	87,241
Total Costs	$217,416	$168,299	$149,258	$68,423	$76,049	$82,725	$83,231	$83,708	$84,840	$85,639	$86,439	$87,241
ANNUAL NET BENEFIT	($217,416)	($168,299)	($129,406)	$6,781	$79,874	$94,673	$131,758	$178,799	$206,370	$209,190	$212,015	$214,924

OVERVIEW OF CASE ASSUMPTIONS

- September 1995 tariffs applied in benefit calculations throughout life of project.
- No consumer surplus calculated in benefit calculations.
- Base case assumptions from ICF model: a) total output, b) portion which is substituted energy, c) portion which is incremental energy.

ECONOMIC COST CALCULATIONS ('000 real 1995 US dollars) Project Year	1995 0	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6
37 **PRODUCTION COSTS**							
38							
39 **Conversion Factors**							
40 **Russian vs. U.S. Costs**							
41 Material	70.0%	73.0%	76.0%	79.0%	82.0%	85.0%	85.5%
42 Equipment	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%	63.0%
43 Labor cost	10.0%	14.0%	18.0%	22.0%	26.0%	30.0%	36.0%
44 Labor productivity factor	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%	62.0%
45 Labor -- Total Cost	20.0%	26.9%	33.3%	39.3%	44.8%	50.0%	58.1%
46 **Russian vs. U.S. Escalation Factors**							
47 Equipment	1.00	1.04	1.08	1.12	1.16	1.20	1.26
48 Material	1.00	1.04	1.09	1.13	1.17	1.21	1.22
49 Labor	1.00	1.35	1.67	1.96	2.24	2.50	2.90
50 Average of Labor and Material (O&M, OOPS escalation)	1.00	1.19	1.38	1.55	1.71	1.86	2.06
51 Composite (average of the 3) (escalation for transmission O&M)	1.00	1.14	1.28	1.40	1.52	1.64	1.79
52							
53 **System Generation**							
54 Nominal Capacity (MW) - GT mode, 1st Module		0	0	300	300	0	0
55 Net Rated Capacity - GT mode. 1st Module		0	0	295	295	0	0
56 Nominal Capacity (MW) - GT mode, 2nd Module		0	0	0	300	300	0
57 Net Rated Capacity - GT mode. 2nd Module		0	0	0	295	295	0
58 Nominal Capacity (MW) - CC mode, 1st Module		0	0	0	450	450	450
59 Net Rated Capacity - CC mode, 1st Module		0	0	0	443	443	443
60 Nominal Capacity (MW) - CC mode, 2nd Module		0	0	0	0	450	450
61 Net Rated Capacity - CC mode, 2nd Module		0	0	0	0	443	443
62 Total Nominal Capacity		0	0	300	750	900	900
63 Total Net Rated Capacity		0	0	295	738	886	886
64 Months of Operation - GT mode, 1st Module		0	0	0	4	8	0
65 Months of Operation - GT mode, 2nd Module		0	0	0	0	10	2
66 Months of Operation - CC mode, 1st Module		0	0	0	0	4	12
67 Months of Operation - CC mode, 2nd Module		0	0	0	0	0	10
68 Load Factor - GT mode *		34.8%	34.8%	35.3%	54.1%	27.4%	0.0%
69 Load Factor - CC mode *		90.2%	90.2%	90.2%	90.2%	90.2%	90.2%
70 Operating Hours - GT mode, 1st Module		0	0	0	1,580	1,598	0
71 Operating Hours - GT mode, 2nd Module		0	0	0	0	1,997	0
72 Operating Hours - CC mode, 1st Module		0	0	0	0	2,634	7,903
73 Operating Hours - CC mode, 2nd Module		0	0	0	0	0	6,586
74 Production (GWh) - GT mode		0	0	0	474	599	0
75 Production (GWh) - CC mode		0	0	0	0	1,185	6,520
76 Total Production (GWh)		0	0	0	474	1,785	6,520
77 Supplied (GWh) - GT mode		0	0	0	467	590	0
78 Supplied (GWh) - CC mode		0	0	0	0	1,167	6,419
79 Total Supplied (GWh) at the busbar		0	0	0	467	1,757	6,419
80							

ECONOMIC COST CALCULATIONS ('000 real 1995 US dollars) Project Year	2002 7	2003 8	2004 9	2005 10	2006 11	2007 12
37 **PRODUCTION COSTS**						
38						
39 **Conversion Factors**						
40 **Russian vs. U.S. Costs**						
41 Material	86.0%	86.5%	87.0%	87.5%	88.0%	88.5%
42 Equipment	66.0%	69.0%	72.0%	75.0%	78.0%	81.0%
43 Labor cost	42.0%	48.0%	54.0%	60.0%	62.7%	65.3%
44 Labor productivity factor	64.0%	66.0%	68.0%	70.0%	72.0%	74.0%
45 Labor -- Total Cost	65.6%	72.7%	79.4%	85.7%	87.0%	88.3%
46 **Russian vs. U.S. Escalation Factors**						
47 Equipment	1.32	1.38	1.44	1.50	1.56	1.62
48 Material	1.23	1.24	1.24	1.25	1.26	1.26
49 Labor	3.28	3.64	3.97	4.29	4.35	4.41
50 Average of Labor and Material (O&M, OOPS escalation)	2.25	2.44	2.61	2.77	2.80	2.84
51 Composite (average of the 3) (escalation for transmission O&M)	1.94	2.08	2.22	2.35	2.39	2.43
52						
53 **System Generation**						
54 Nominal Capacity (MW) - GT mode, 1st Module	0	0	0	0	0	0
55 Net Rated Capacity - GT mode. 1st Module	0	0	0	0	0	0
56 Nominal Capacity (MW) - GT mode, 2nd Module	0	0	0	0	0	0
57 Net Rated Capacity - GT mode. 2nd Module	0	0	0	0	0	0
58 Nominal Capacity (MW) - CC mode, 1st Module	450	450	450	450	450	450
59 Net Rated Capacity - CC mode, 1st Module	443	443	443	443	443	443
60 Nominal Capacity (MW) - CC mode, 2nd Module	450	450	450	450	450	450
61 Net Rated Capacity - CC mode, 2nd Module	443	443	443	443	443	443
62 Total Nominal Capacity	900	900	900	900	900	900
63 Total Net Rated Capacity	886	886	886	886	886	886
64 Months of Operation - GT mode, 1st Module	0	0	0	0	0	0
65 Months of Operation - GT mode, 2nd Module	0	0	0	0	0	0
66 Months of Operation - CC mode, 1st Module	12	12	12	12	12	12
67 Months of Operation - CC mode, 2nd Module	12	12	12	12	12	12
68 Load Factor - GT mode *	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
69 Load Factor - CC mode *	90.2%	90.2%	90.2%	90.2%	90.2%	90.2%
70 Operating Hours - GT mode, 1st Module	0	0	0	0	0	0
71 Operating Hours - GT mode, 2nd Module	0	0	0	0	0	0
72 Operating Hours - CC mode, 1st Module	7,903	7,903	7,903	7,903	7,903	7,903
73 Operating Hours - CC mode, 2nd Module	7,903	7,903	7,903	7,903	7,903	7,903
74 Production (GWh) - GT mode	0	0	0	0	0	0
75 Production (GWh) - CC mode	7,113	7,113	7,113	7,113	7,113	7,113
76 Total Production (GWh)	7,113	7,113	7,113	7,113	7,113	7,113
77 Supplied (GWh) - GT mode	0	0	0	0	0	0
78 Supplied (GWh) - CC mode	7,002	7,002	7,002	7,002	7,002	7,002
79 Total Supplied (GWh) at the busbar	7,002	7,002	7,002	7,002	7,002	7,002
80						

* Load Factors shown differ from those in the Financial Model. These load factors, for purposes of economic analysis, are based on output figures supplied by the ICF model.

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ECONOMIC CAPITAL COST CALCULATIONS

115		6.29%	21.90%	25.08%	19.11%	27.62%	100.00%
116	**Expenditure Profile**	Project Year					
117		1	2	3	4	5	Total
118	Civil Works	8%	28%	32%	24%	8%	100%
119	Combustion Turbine	8%	28%	32%	24%	8%	100%
120	HRSG	8%	28%	32%	24%	8%	100%
121	Steam Turbines	8%	28%	32%	24%	8%	100%
122	Distributed Control System	8%	28%	32%	24%	8%	100%
123	Mechanical Package	8%	28%	32%	24%	8%	100%
124	Electrical Package	8%	28%	32%	24%	8%	100%
125	Switchyard	8%	28%	32%	24%	8%	100%
126	Engineering & Project Mgmt.	8%	28%	32%	24%	8%	100%
127	Transmission Line	30%	40%	15%	15%	0%	100%
128	Gas Pipeline	40%	60%	0%	0%	0%	100%
129							
130							

131	**Escalation Matrix**	Russian vs. U.S. Real Escalation			
132	Is each component to be escalated?	Equipment	Material	Labor	Indirect
133	Civil Works	yes	yes	yes	yes
134	Combustion Turbine	yes	yes	yes	yes
135	HRSG	yes	yes	yes	yes
136	Steam Turbines	yes	yes	yes	yes
137	Distributed Control System	yes	yes	yes	yes
138	Mechanical Package	yes	yes	yes	yes
139	Electrical Package	yes	yes	yes	yes
140	Switchyard	yes	yes	yes	yes
141	Engineering & Project Mgmt.	yes	yes	yes	yes
142	Transmission Line	yes	yes	yes	yes
143	Gas Pipeline	yes	yes	yes	yes
144					
145					

146	**Real Escalation Factors**	Project Year					
147		0	1	2	3	4	5
148	RUSSIAN VS. U.S. COSTS						
149	Material	70.0%	73.0%	76.0%	79.0%	82.0%	85.0%
150	Equipment	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%
151	Labor	10.0%	14.0%	18.0%	22.0%	26.0%	30.0%
152	Labor productivity	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%
153	Labor -- total cost	20.0%	26.9%	33.3%	39.3%	44.8%	50.0%
154	RUSSIAN VS. U.S. ESCALATION FACTORS						
155	Equipment	1.00	1.04	1.08	1.12	1.16	1.20
156	Material	1.00	1.04	1.09	1.13	1.17	1.21
157	Labor	1.00	1.40	1.80	2.20	2.60	3.00
158	Average of Labor & Material (Indirect)	1.00	1.22	1.44	1.66	1.89	2.11
159							

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SCENARIO: CASE 3.B -- STARTUP DELAYS OF TWO YEARS

ECONOMIC RATE OF RETURN	**18.3%**
Net Present Value at 15% Discount Rate (1995 US $ '000)	$130,903

ECONOMIC BENEFIT SUMMARY	1996-1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Quantity of Substituted Energy (GWh)	0	0	0	0	0	2,590	2,247	1,068	372	299	226	151
Quantity of Incremental Energy (GWh)	0	0	0	0	1,015	3,331	4,137	5,163	5,768	5,832	5,895	5,960
Energy Lost in Transmission/Distribution (GWh)	0	0	0	0	152	498	618	771	862	871	881	891
Total Energy Supplied (GWh)	0	0	0	0	1,167	6,419	7,002	7,002	7,002	7,002	7,002	7,002
Benefit of Substituted Energy (1995 US $ '000)	$0	$0	$0	$0	$0	$10,191	$9,229	$4,559	$1,654	$1,347	$1,032	$698
Benefit of Incremental Energy (1995 US $ '000)	0	0	0	0	50,114	164,911	205,759	257,947	289,556	293,481	297,422	301,467
Total Benefit of Energy Supplied (1995 US $ '000)	$0	$0	$0	$0	$50,114	$175,102	$214,988	$262,506	$291,210	$294,828	$298,454	$302,165
ECONOMIC COST SUMMARY												
Total Capital Costs	$217,416	$166,050	$135,689	$39,150	$0	$0	$0	$0	$0	$0	$0	$0
Total Production Costs	0	2,250	6,445	7,990	20,794	76,582	83,231	83,708	84,840	85,639	86,439	87,241
Total Costs	$217,416	$168,299	$142,134	$47,140	$20,794	$76,582	$83,231	$83,708	$84,840	$85,639	$86,439	$87,241
ANNUAL NET BENEFIT	($217,416)	($168,299)	($142,134)	($47,140)	$29,320	$98,520	$131,758	$178,799	$206,370	$209,190	$212,015	$214,924

OVERVIEW OF CASE ASSUMPTIONS

- Operating startup of simple cycle delayed by one year and combined cycle modules delayed by two years (with capital expenditures still timed according to Base Case plan).
- September 1995 tariffs applied in benefit calculations throughout life of project.
- No consumer surplus calculated in benefit calculations.
- Base case assumptions from ICF model: a) total output, b) portion which is substituted energy, c) portion which is incremental energy.

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ECONOMIC COST CALCULATIONS ('000 real 1995 US dollars) — Project Year	1995 0	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11	2007 12
37 **PRODUCTION COSTS**													
38													
39 **Conversion Factors**													
40 **Russian vs. U.S. Costs**													
41 Material	70.0%	73.0%	76.0%	79.0%	82.0%	85.0%	85.5%	86.0%	86.5%	87.0%	87.5%	88.0%	88.5%
42 Equipment	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%	63.0%	66.0%	69.0%	72.0%	75.0%	78.0%	81.0%
43 Labor cost	10.0%	14.0%	18.0%	22.0%	26.0%	30.0%	36.0%	42.0%	48.0%	54.0%	60.0%	62.7%	65.3%
44 Labor productivity factor	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%	62.0%	64.0%	66.0%	68.0%	70.0%	72.0%	74.0%
45 Labor -- Total Cost	20.0%	26.9%	33.3%	39.3%	44.8%	50.0%	58.1%	65.6%	72.7%	79.4%	85.7%	87.0%	88.3%
46 **Russian vs. U.S. Escalation Factors**													
47 Equipment	1.00	1.04	1.08	1.12	1.16	1.20	1.26	1.32	1.38	1.44	1.50	1.56	1.62
48 Material	1.00	1.04	1.09	1.13	1.17	1.21	1.22	1.23	1.24	1.24	1.25	1.26	1.26
49 Labor	1.00	1.35	1.67	1.96	2.24	2.50	2.90	3.28	3.64	3.97	4.29	4.35	4.41
50 Average of Labor and Material (O&M, OOPS escalation)	1.00	1.19	1.38	1.55	1.71	1.86	2.06	2.25	2.44	2.61	2.77	2.80	2.84
51 Composite (average of the 3) (escalation for transmission O&M)	1.00	1.14	1.28	1.40	1.52	1.64	1.79	1.94	2.08	2.22	2.35	2.39	2.43
52													
53 **System Generation**													
54 Nominal Capacity (MW) - GT mode, 1st Module		0	0	300	300	0	0	0	0	0	0	0	0
55 Net Rated Capacity - GT mode, 1st Module		0	0	295	295	0	0	0	0	0	0	0	0
56 Nominal Capacity (MW) - GT mode, 2nd Module		0	0	0	300	300	0	0	0	0	0	0	0
57 Net Rated Capacity - GT mode, 2nd Module		0	0	0	295	295	0	0	0	0	0	0	0
58 Nominal Capacity (MW) - CC mode, 1st Module		0	0	0	450	450	450	450	450	450	450	450	450
59 Net Rated Capacity - CC mode, 1st Module		0	0	0	443	443	443	443	443	443	443	443	443
60 Nominal Capacity (MW) - CC mode, 2nd Module		0	0	0	0	450	450	450	450	450	450	450	450
61 Net Rated Capacity - CC mode, 2nd Module		0	0	0	0	443	443	443	443	443	443	443	443
62 Total Nominal Capacity		0	0	300	750	900	900	900	900	900	900	900	900
63 Total Net Rated Capacity		0	0	295	738	886	886	886	886	886	886	886	886
64 Months of Operation - GT mode, 1st Module		0	0	0	0	4	8	0	0	0	0	0	0
65 Months of Operation - GT mode, 2nd Module		0	0	0	0	0	10	2	0	0	0	0	0
66 Months of Operation - CC mode, 1st Module		0	0	0	0	0	4	12	12	12	12	12	12
67 Months of Operation - CC mode, 2nd Module		0	0	0	0	0	0	10	12	12	12	12	12
68 Load Factor - GT mode *		34.8%	34.8%	35.3%	54.1%	27.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
69 Load Factor - CC mode *		90.2%	90.2%	90.2%	90.2%	90.2%	90.2%	90.2%	90.2%	90.2%	90.2%	90.2%	90.2%
70 Operating Hours - GT mode, 1st Module		0	0	0	0	799	0	0	0	0	0	0	0
71 Operating Hours - GT mode, 2nd Module		0	0	0	0	0	0	0	0	0	0	0	0
72 Operating Hours - CC mode, 1st Module		0	0	0	0	0	2,634	7,903	7,903	7,903	7,903	7,903	7,903
73 Operating Hours - CC mode, 2nd Module		0	0	0	0	0	0	6,586	7,903	7,903	7,903	7,903	7,903
74 Production (GWh) - GT mode		0	0	0	0	0	0	0	0	0	0	0	0
75 Production (GWh) - CC mode		0	0	0	0	0	1,185	6,520	7,113	7,113	7,113	7,113	7,113
76 Total Production (GWh)		0	0	0	0	0	1,185	6,520	7,113	7,113	7,113	7,113	7,113
77 Supplied (GWh) - GT mode		0	0	0	0	0	0	0	0	0	0	0	0
78 Supplied (GWh) - CC mode		0	0	0	0	0	1,167	6,419	7,002	7,002	7,002	7,002	7,002
79 Total Supplied (GWh) at the busbar		0	0	0	0	0	1,167	6,419	7,002	7,002	7,002	7,002	7,002
80													

One-year delay of simple cycle and two-year delay of combined cycle modules.

* Load Factors shown differ from those in the Financial Model. These load factors, for purposes of economic analysis, are based on output figures supplied by the ICF model.

ECONOMIC CAPITAL COST CALCULATIONS

Expenditure Profile	Project Year					
	1	2	3	4	5	Total
Civil Works	8%	28%	32%	24%	8%	100%
Combustion Turbine	8%	28%	32%	24%	8%	100%
HRSG	8%	28%	32%	24%	8%	100%
Steam Turbines	8%	28%	32%	24%	8%	100%
Distributed Control System	8%	28%	32%	24%	8%	100%
Mechanical Package	8%	28%	32%	24%	8%	100%
Electrical Package	8%	28%	32%	24%	8%	100%
Switchyard	8%	28%	32%	24%	8%	100%
Engineering & Project Mgmt.	8%	28%	32%	24%	8%	100%
Transmission Line	30%	40%	15%	15%	0%	100%
Gas Pipeline	40%	60%	0%	0%	0%	100%

Capital expenditures still timed according to Base Case plan.

Escalation Matrix	Russian vs. U.S. Real Escalation			
Is each component to be escalated?	Equipment	Material	Labor	Indirect
Civil Works	yes	yes	yes	yes
Combustion Turbine	yes	yes	yes	yes
HRSG	yes	yes	yes	yes
Steam Turbines	yes	yes	yes	yes
Distributed Control System	yes	yes	yes	yes
Mechanical Package	yes	yes	yes	yes
Electrical Package	yes	yes	yes	yes
Switchyard	yes	yes	yes	yes
Engineering & Project Mgmt.	yes	yes	yes	yes
Transmission Line	yes	yes	yes	yes
Gas Pipeline	yes	yes	yes	yes

Real Escalation Factors	Project Year					
	0	1	2	3	4	5
RUSSIAN VS. U.S. COSTS						
Material	70.0%	73.0%	76.0%	79.0%	82.0%	85.0%
Equipment	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%
Labor	10.0%	14.0%	18.0%	22.0%	26.0%	30.0%
Labor productivity	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%
Labor -- total cost	20.0%	26.9%	33.3%	39.3%	44.8%	50.0%
RUSSIAN VS. U.S. ESCALATION FACTORS						
Equipment	1.00	1.04	1.08	1.12	1.16	1.20
Material	1.00	1.04	1.09	1.13	1.17	1.21
Labor	1.00	1.40	1.80	2.20	2.60	3.00
Average of Labor & Material (Indirect)	1.00	1.22	1.44	1.66	1.89	2.11

SCENARIO: CASE 4.A -- FUEL COST INCREASE OF 20%

ECONOMIC RATE OF RETURN 18.3%

Net Present Value at 15% Discount Rate (1995 US $ '000) $122,659

ECONOMIC BENEFIT SUMMARY	1996-1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Quantity of Substituted Energy (GWh)	0	0	1,914	3,904	3,638	3,173	2,247	1,068	372	299	226	151
Quantity of Incremental Energy (GWh)	0	265	1,177	2,291	2,927	3,331	4,137	5,163	5,768	5,832	5,895	5,960
Energy Lost in Transmission/Distribution (GWh)	0	40	176	342	437	498	618	771	862	871	881	891
Total Energy Supplied (GWh)	0	305	3,267	6,537	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002
Benefit of Substituted Energy (1995 US $ '000)	$0	$0	$0	$6,004	$6,673	$6,399	$4,918	$2,510	$933	$762	$585	$396
Benefit of Incremental Energy (1995 US $ '000)	0	12,866	57,571	112,708	144,459	164,911	205,759	257,947	289,556	293,481	297,422	301,467
Total Benefit of Energy Supplied (1995 US $ '000)	$0	$12,866	$57,571	$118,713	$151,133	$171,310	$210,677	$260,457	$290,489	$294,243	$298,007	$301,863
ECONOMIC COST SUMMARY												
Total Capital Costs	$217,416	$166,050	$135,689	$39,150	$0	$0	$0	$0	$0	$0	$0	$0
Total Production Costs	0	7,782	59,129	90,137	95,837	96,373	96,879	97,355	98,625	99,561	100,500	101,443
Total Costs	$217,416	$173,831	$194,818	$129,287	$95,837	$96,373	$96,879	$97,355	$98,625	$99,561	$100,500	$101,443
ANNUAL NET BENEFIT	($217,416)	($160,965)	($137,247)	($10,574)	$55,296	$74,937	$113,798	$163,101	$191,864	$194,682	$197,507	$200,420

OVERVIEW OF CASE ASSUMPTIONS

- Fuel costs raised from $50 to $60 per 1000 m^3 (20% increase).
- September 1995 tariffs applied in benefit calculations throughout life of project.
- No consumer surplus calculated in benefit calculations.
- Base case assumptions from ICF model: a) total output, b) portion which is substituted energy, c) portion which is incremental energy.

	ECONOMIC COST CALCULATIONS ('000 real 1995 US dollars)	Project Year		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
				0	1	2	3	4	5	6	7	8	9	10	11	12
81	**Fuel Consumptions Calculations**	Heat Rate														
82	BTU/kWh - GT mode	10,080			0.00	0.00	3.12	21.50	1.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00
83	BTU/kWh - CC mode	6,771			0.00	0.00	0.00	8.03	44.15	48.16	48.16	48.16	48.16	48.16	48.16	48.16
84	Gas - million MCM				0.000	0.000	0.088	0.837	1.285	1.365	1.365	1.365	1.365	1.365	1.365	1.365
85	Cost (per MCM) real escalation begins 2005	Fuel costs		$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.60	$61.21	$61.82
86	Variable Fuel Cost ($/kWh)	increase 20%			$0.0000	$0.0000	$0.0171	$0.0151	$0.0116	$0.0115	$0.0115	$0.0115	$0.0115	$0.0116	$0.0117	$0.0119
87																
88	**O&M Calculations**	Total 1995	$/kW													
89	Fixed O&M Calculations	'000 $	(886 kW)													
90	Non-Russian Materials ($/kW/yr)	$3,550	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068
91	Non-Russian OOPs ($/kW/yr)	$225	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540
92	Russian Materials ($/kW/yr) (escalated)	$360	$0.4063	$0.4063	$0.4237	$0.4411	$0.4586	$0.4760	$0.4934	$0.4963	$0.4992	$0.5021	$0.5050	$0.5079	$0.5108	$0.5137
93	Russian Labor ($/kW/yr) (escalated)	$935	$1.0553	$1.0553	$1.4206	$1.7588	$2.0729	$2.3653	$2.6383	$3.0638	$3.4627	$3.8375	$4.1902	$4.5227	$4.5925	$4.6586
94	Russian OOPs ($/kW/yr) (esc., avg.Mat&Lab)	$405	$0.4571	$0.4571	$0.5460	$0.6291	$0.7069	$0.7800	$0.8489	$0.9427	$1.0307	$1.1135	$1.1916	$1.2652	$1.2820	$1.2979
95	Total Fixed O&M ($/kW/y)	$5,475	$6.1795	$6.1795	$6.6511	$7.0898	$7.4991	$7.8821	$8.2413	$8.7635	$9.2534	$9.7138	$10.1475	$10.5566	$10.6460	$10.7309
96																
97		Total 1995	$/MWh													
98	Variable O&M Calculations *	000 $	(6600 GWh)													
99	Non-Russian Materials ($/kWh)	$3,550	$0.53788	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054
100	Non-Russian OOPs ($/kWh)	$225	$0.03409	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003
101	Russian Materials ($/kWh) (escalated)	$760	$0.11515	$0.00012	$0.00012	$0.00013	$0.00013	$0.00013	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00015
102	Russian Labor ($/kWh) (escalated)	$35	$0.00530	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00002	$0.00002	$0.00002	$0.00002	$0.00002	$0.00002	$0.00002
103	Russian OOPs ($/kWh) (esc., avg.Mat&Lab)	$115	$0.01742	$0.00002	$0.00002	$0.00002	$0.00003	$0.00003	$0.00003	$0.00004	$0.00004	$0.00004	$0.00005	$0.00005	$0.00005	$0.00005
104	Total Variable O&M ($/kWh)	$4,685	$0.70985	$0.00071	$0.00072	$0.00073	$0.00074	$0.00075	$0.00076	$0.00076	$0.00077	$0.00078	$0.00078	$0.00079	$0.00079	$0.00079
105																
106	Total Variable Cost (Fuel & O&M) ($/kWh)			nm	nm	nm	$ 0.017878	$ 0.015878	$ 0.012372	$ 0.012277	$ 0.012283	$ 0.012289	$ 0.012294	$ 0.012415	$ 0.012533	$ 0.012652
107																
108	**Substituted Energy Calculations**															
109	"Average" Marginal Cost of Region w/o Mostovskoy															
110	Marginal Fuel Cost ($/kWh)			$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012211	$ 0.012333	$ 0.012456
111	Marginal Variable O&M Cost ($/kWh) (esc., avg.Mat&Lab)			$ 0.000980	$ 0.001171	$ 0.001349	$ 0.001516	$ 0.001672	$ 0.001820	$ 0.002021	$ 0.002210	$ 0.002387	$ 0.002555	$ 0.002713	$ 0.002748	$ 0.002783
112	Total Marginal Cost w/o Mostovskoy ($/kWh)			$ 0.013070	$ 0.013261	$ 0.013439	$ 0.013606	$ 0.013762	$ 0.013910	$ 0.014111	$ 0.014300	$ 0.014477	$ 0.014645	$ 0.014923	$ 0.015081	$ 0.015239
113	Marginal Cost Savings ($/kWh)			nm	nm	nm	nm	nm	$ 0.001538	$ 0.001834	$ 0.002017	$ 0.002188	$ 0.002350	$ 0.002509	$ 0.002548	$ 0.002587
114																
115	**Costs of Production**															
116	Variable O&M				$0	$0	$229	$2,484	$5,029	$5,434	$5,478	$5,519	$5,559	$5,597	$5,610	$5,622
117	Fixed O&M				$0	$0	$2,250	$5,912	$7,417	$7,887	$8,328	$8,742	$9,133	$9,501	$9,581	$9,658
118	Generation Costs				$0	$0	$5,303	$50,200	$77,117	$81,887	$81,887	$81,887	$81,887	$82,706	$83,533	$84,369
119	Transmission O&M ($350,000/yr, escalated by composite)				$0	$0	$0	$533	$573	$628	$680	$729	$776	$821	$836	$852
120	Total Production Costs				0	0	7,782	59,129	90,137	95,837	96,373	96,879	97,355	98,625	99,561	100,500

* Variable O&M figures were available for combined cycle operation only. Previous model runs show separate figures for variable O&M under GT and CC mode. Under these previous runs, data provided showed a lower variable O&M figure per kWh for GT operation than for CC. Accordingly, an assumption that the variable O&M for GT is the same as for CC errs on the side of conservatism.

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SCENARIO: CASE 4.B – MAXIMUM FUEL COST INCREASE TO YIELD EIRR OF 15%

ECONOMIC RATE OF RETURN	**15.0%**
Net Present Value at 15% Discount Rate (1995 US $ '000)	$0

	1996-1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
ECONOMIC BENEFIT SUMMARY												
Quantity of Substituted Energy (GWh)	0	0	1,914	3,904	3,638	3,173	2,247	1,068	372	299	226	151
Quantity of Incremental Energy (GWh)	0	265	1,177	2,291	2,927	3,331	4,137	5,163	5,768	5,832	5,895	5,960
Energy Lost in Transmission/Distribution (GWh)	0	40	176	342	437	498	618	771	862	871	881	891
Total Energy Supplied (GWh)	0	305	3,267	6,537	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002
Benefit of Substituted Energy (1995 US $ '000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Benefit of Incremental Energy (1995 US $ '000)	0	12,866	57,571	112,708	144,459	164,911	205,759	257,947	289,556	293,481	297,422	301,467
Total Benefit of Energy Supplied (1995 US $ '000)	$0	$12,866	$57,571	$112,708	$144,459	$164,911	$205,759	$257,947	$289,556	$293,481	$297,422	$301,467
ECONOMIC COST SUMMARY												
Total Capital Costs	$217,416	$166,050	$135,689	$39,150	$0	$0	$0	$0	$0	$0	$0	$0
Total Production Costs	0	9,518	75,565	115,386	122,647	123,184	123,689	124,166	125,703	126,910	128,123	129,342
Total Costs	$217,416	$175,568	$211,254	$154,536	$122,647	$123,184	$123,689	$124,166	$125,703	$126,910	$128,123	$129,342
ANNUAL NET BENEFIT	($217,416)	($162,701)	($153,683)	($41,827)	$21,812	$41,727	$82,070	$133,781	$163,853	$166,571	$169,299	$172,125

OVERVIEW OF CASE ASSUMPTIONS

- Maximum tolerable fuel costs with EIRR of 15% – $80 per 1000 m^3 (60% increase).
- September 1995 tariffs applied in benefit calculations throughout life of project.
- No consumer surplus calculated in benefit calculations.
- Base case assumptions from ICF model: a) total output, b) portion which is substituted energy, c) portion which is incremental energy.

	ECONOMIC COST CALCULATIONS ('000 real 1995 US dollars)	Project Year		1995 0	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11	2007 12
81	**Fuel Consumptions Calculations**	Heat Rate														
82	BTU/kWh - GT mode	10,080			0.00	0.00	3.12	21.50	1.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00
83	BTU/kWh - CC mode	6,771			0.00	0.00	0.00	8.03	44.15	48.16	48.16	48.16	48.16	48.16	48.16	48.16
84	Gas - million MCM				0.000	0.000	0.088	0.837	1.285	1.365	1.365	1.365	1.365	1.365	1.365	1.365
85	Cost (per MCM) real escalation begins 2005	Maximum fuel costs increase to yield EIRR of 15%	→	$79.64	$79.64	$79.64	$79.64	$79.64	$79.64	$79.64	$79.64	$79.64	$79.64	$80.44	$81.25	$82.06
86	Variable Fuel Cost ($/kWh)				$0.0000	$0.0000	$0.0228	$0.0201	$0.0154	$0.0153	$0.0153	$0.0153	$0.0153	$0.0154	$0.0156	$0.0157
87																
88	**O&M Calculations**	Total 1995	$/kW													
89	Fixed O&M Calculations	'000 $	(886 kW)													
90	Non-Russian Materials ($/kW/yr)	$3,550	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068	$4.0068
91	Non-Russian OOPs ($/kW/yr)	$225	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540	$0.2540
92	Russian Materials ($/kW/yr) (escalated)	$360	$0.4063	$0.4063	$0.4237	$0.4411	$0.4586	$0.4760	$0.4934	$0.4963	$0.4992	$0.5021	$0.5050	$0.5079	$0.5108	$0.5137
93	Russian Labor ($/kW/yr) (escalated)	$935	$1.0553	$1.0553	$1.4206	$1.7588	$2.0729	$2.3653	$2.6383	$3.0638	$3.4627	$3.8375	$4.1902	$4.5227	$4.5925	$4.6586
94	Russian OOPs ($/kW/yr) (esc., avg.Mat&Lab)	$405	$0.4571	$0.4571	$0.5460	$0.6291	$0.7069	$0.7800	$0.8489	$0.9427	$1.0307	$1.1135	$1.1916	$1.2652	$1.2820	$1.2979
95	Total Fixed O&M ($/kW/y)	$5,475	$6.1795	$6.1795	$6.6511	$7.0898	$7.4991	$7.8821	$8.2413	$8.7635	$9.2534	$9.7138	$10.1475	$10.5566	$10.6460	$10.7309
96																
97		Total 1995	$/MWh													
98	Variable O&M Calculations *	000 $	(6600 GWh)													
99	Non-Russian Materials ($/kWh)	$3,550	$0.53788	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054	$0.00054
100	Non-Russian OOPs ($/kWh)	$225	$0.03409	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003	$0.00003
101	Russian Materials ($/kWh) (escalated)	$760	$0.11515	$0.00012	$0.00012	$0.00013	$0.00013	$0.00013	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00015
102	Russian Labor ($/kWh) (escalated)	$35	$0.00530	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00002	$0.00002	$0.00002	$0.00002	$0.00002	$0.00002	$0.00002
103	Russian OOPs ($/kWh) (esc., avg.Mat&Lab)	$115	$0.01742	$0.00002	$0.00002	$0.00002	$0.00003	$0.00003	$0.00003	$0.00004	$0.00004	$0.00004	$0.00005	$0.00005	$0.00005	$0.00005
104	Total Variable O&M ($/kWh)	$4,685	$0.70985	$0.00071	$0.00072	$0.00073	$0.00074	$0.00075	$0.00076	$0.00076	$0.00077	$0.00078	$0.00078	$0.00079	$0.00079	$0.00079
105																
106	Total Variable Cost (Fuel & O&M) ($/kWh)			nm	nm	nm	$ 0.023490	$ 0.020831	$ 0.016174	$ 0.016046	$ 0.016052	$ 0.016058	$ 0.016064	$ 0.016222	$ 0.016378	$ 0.016536
107																
108	**Substituted Energy Calculations**															
109	"Average" Marginal Cost of Region w/o Mostovskoy															
110	Marginal Fuel Cost ($/kWh)			$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012090	$ 0.012211	$ 0.012333	$ 0.012456
111	Marginal Variable O&M Cost ($/kWh) (esc., avg.Mat&Lab)			$ 0.000980	$ 0.001171	$ 0.001349	$ 0.001516	$ 0.001672	$ 0.001820	$ 0.002021	$ 0.002210	$ 0.002387	$ 0.002555	$ 0.002713	$ 0.002748	$ 0.002783
112	Total Marginal Cost w/o Mostovskoy ($/kWh)			$ 0.013070	$ 0.013261	$ 0.013439	$ 0.013606	$ 0.013762	$ 0.013910	$ 0.014111	$ 0.014300	$ 0.014477	$ 0.014645	$ 0.014923	$ 0.015081	$ 0.015239
113	Marginal Cost Savings ($/kWh)			nm	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
114																
115	**Costs of Production**															
116	Variable O&M				$0	$0	$229	$2,484	$5,029	$5,434	$5,478	$5,519	$5,559	$5,597	$5,610	$5,622
117	Fixed O&M				$0	$0	$2,250	$5,912	$7,417	$7,887	$8,328	$8,742	$9,133	$9,501	$9,581	$9,658
118	Generation Costs				$0	$0	$7,040	$66,636	$102,366	$108,698	$108,698	$108,698	$108,698	$109,785	$110,883	$111,991
119	Transmission O&M ($350,000/yr, escalated by composite)				$0	$0	$0	$533	$573	$628	$680	$729	$776	$821	$836	$852
120	Total Production Costs				0	0	9,518	75,565	115,386	122,647	123,184	123,689	124,166	125,703	126,910	128,123

* Variable O&M figures were available for combined cycle operation only. Previous model runs show separate figures for variable O&M under GT and CC mode. Under these previous runs, data provided showed a lower variable O&M figure per kWh for GT operation than for CC. Accordingly, an assumption that the variable O&M for GT is the same as for CC errs on the side of conservatism.

SCENARIO: CASE 5 – LOW DEMAND

ECONOMIC RATE OF RETURN	17.8%
Net Present Value at 15% Discount Rate (1995 US $ '000)	$108.836

ECONOMIC BENEFIT SUMMARY	1996-1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Quantity of Substituted Energy (GWh)	0	9	2,092	4,639	4,533	4,081	3,201	2,097	1,312	0	0	0
Quantity of Incremental Energy (GWh)	0	209	785	1,518	2,148	2,541	3,307	4,267	4,950	6,092	6,092	6,092
Energy Lost in Transmission/Distribution (GWh)	0	31	117	227	321	380	494	638	740	910	910	910
Total Energy Supplied (GWh)	0	249	2,994	6,384	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002
Benefit of Substituted Energy (1995 US $ '000)	$0	$0	$1,168	$15,816	$17,013	$16,062	$13,149	$8,952	$5,836	$7,198	$8,591	$10,014
Benefit of Incremental Energy (1995 US $ '000)	0	10,150	38,400	74,697	106,028	125,804	164,459	213,223	248,488	236,636	224,721	212,743
Total Benefit of Energy Supplied (1995 US $ '000)	$0	$10,150	$39,568	$90,513	$123,041	$141,866	$177,609	$222,175	$254,323	$243,833	$233,311	$222,757
ECONOMIC COST SUMMARY												
Total Capital Costs	$217,416	$166,050	$135,689	$39,150	$0	$0	$0	$0	$0	$0	$0	$0
Total Production Costs	0	6,054	46,609	76,086	82,189	82,725	83,231	83,708	84,840	85,639	86,439	87,241
Total Costs	$217,416	$172,103	$182,298	$115,236	$82,189	$82,725	$83,231	$83,708	$84,840	$85,639	$86,439	$87,241
ANNUAL NET BENEFIT	($217,416)	($161,954)	($142,730)	($24,723)	$40,852	$59,140	$94,378	$138,467	$169,483	$158,194	$146,873	$135,516

OVERVIEW OF CASE ASSUMPTIONS

- Low demand case, per ICF model.
- September 1995 tariffs applied in benefit calculations throughout life of project.
- No consumer surplus calculated in benefit calculations.
- Base case assumptions from ICF model: a) total output, b) portion which is substituted energy, c) portion which is incremental energy.

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ECONOMIC BENEFIT CALCULATIONS By Customer Category and By Year	1995 0	1996 1	1997 2	1998 3	1999 4	2000 5	2001 6	2002 7	2003 8	2004 9	2005 10	2006 11	2007 12	2008 13
1 **Total Supplied (GWh) at the busbar (after 1.56% internal losses)**		0	0	249	2,994	6,384	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002
2														
3 **Unserved Energy Before Losses (from ICF model)**		0	0	240	902	1,745	2,469	2,921	3,801	4,905	5,690	8,232	10,775	13,317
4														
5 **Substituted Energy (GWh) (line 1 minus line 3)**		0	0	9	2,092	4,639	4,533	4,081	3,201	2,097	1,312	0	0	0
6 Cost Savings ($/kWh) (See Economic Costs Calculations, Line:) 113		nm	nm	nm	0.00056	0.00341	0.00375	0.00394	0.00411	0.00427	0.00445	0.00451	0.00456	0.00462
7 **Value of Substituted Energy ($ '000)**		0	0	0	1,168	15,816	17,013	16,062	13,149	8,952	5,836	0	0	0
8														
9 **Incremental Energy Before Losses (line 1 minus line 5)**		0	0	240	902	1,745	2,469	2,921	3,801	4,905	5,690	7,002	7,002	7,002
10 Transmission/Distribution Loss 13%		0	0	31	117	227	321	380	494	638	740	910	910	910
11 **Incremental Energy After Losses**		0	0	209	785	1,518	2,148	2,541	3,307	4,267	4,950	6,092	6,092	6,092
12														
13 **Percentage Consumption by Classification**														
14 Industry	33.7%	34.8%	35.3%	36.3%	37.0%	37.7%	38.0%	38.3%	38.8%	39.2%	39.7%	39.9%	40.0%	40.2%
15 Agriculture	18.5%	18.3%	18.0%	17.9%	17.7%	17.4%	17.3%	17.1%	17.0%	16.9%	16.7%	16.8%	16.9%	16.9%
16 Transport	6.8%	6.9%	7.0%	7.2%	7.3%	7.5%	7.5%	7.6%	7.8%	7.9%	8.0%	8.0%	8.1%	8.1%
17 Residential/Other	41.0%	39.9%	39.6%	38.7%	38.0%	37.5%	37.2%	36.9%	36.5%	36.0%	35.6%	35.3%	35.0%	34.8%
18														
19 **Consumption by Classification (GWh)**														
20 Industry		0	0	76	291	572	815	974	1282	1673	1964	2428	2438	2449
21 Agriculture		0	0	37	139	265	372	436	563	721	829	1023	1027	1030
22 Transport		0	0	15	57	113	162	194	257	337	396	490	492	494
23 Residential/Other		0	0	81	298	569	798	938	1205	1537	1761	2151	2135	2119
24 Total Consumption		0	0	209	785	1,518	2,148	2,541	3,307	4,267	4,950	6,092	6,092	6,092
25														
26 **Tariff by Classification (Roubles)**	April '95	Sept. '95		Converted	April '95	Sept. '95	Avg. '95							
27 Industry	150	298		to 1995	0.0506	0.0694	0.0600							
28 Agriculture	101	260		Dollars	0.0341	0.0606	0.0473							
29 Transport	150	298			0.0506	0.0694	0.0600							
30 Residential/Other	36	84			0.0121	0.0196	0.0159							
31														
32 **PPP Ratio of Price Index (3 month average)**	(Feb-Apr)	(Aug-Oct)												
33 Industry	2,963	4,293												
34 Agriculture	2,963	4,293												
35 Transport	2,963	4,293												
36 Residential/Other	2,963	4,293												
37														
38 **Tariff by Classification (September 1995 Prices Used Throughout)**														
39 Industry	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694
40 Agriculture	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606	0.0606
41 Transport	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694	0.0694
42 Residential/Other	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196	0.0196
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SCENARIO: CASE 6 -- MINIMUM TARIFF TO YIELD EIRR OF 15%

ECONOMIC RATE OF RETURN	**15.0%**
Net Present Value at 15% Discount Rate (1995 US $ '000)	($0)

	1996-1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
ECONOMIC BENEFIT SUMMARY												
Quantity of Substituted Energy (GWh)	0	0	1,914	3,904	3,638	3,173	2,247	1,068	372	299	226	151
Quantity of Incremental Energy (GWh)	0	265	1,177	2,291	2,927	3,331	4,137	5,163	5,768	5,832	5,895	5,960
Energy Lost in Transmission/Distribution (GWh)	0	40	176	342	437	498	618	771	862	871	881	891
Total Energy Supplied (GWh)	0	305	3,267	6,537	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002
Benefit of Substituted Energy (1995 US $ '000)	$0	$0	$777	$13,561	$13,654	$12,488	$9,229	$4,559	$1,654	$1,347	$1,032	$698
Benefit of Incremental Energy (1995 US $ '000)	0	10,109	45,235	88,557	113,505	129,574	161,670	202,675	227,511	230,595	233,691	236,870
Total Benefit of Energy Supplied (1995 US $ '000)	$0	$10,109	$46,012	$102,118	$127,159	$142,062	$170,899	$207,234	$229,165	$231,942	$234,723	$237,567
ECONOMIC COST SUMMARY												
Total Capital Costs	$217,416	$166,050	$135,689	$39,150	$0	$0	$0	$0	$0	$0	$0	$0
Total Production Costs	0	6,898	50,762	77,284	82,189	82,725	83,231	83,708	84,840	85,639	86,439	87,241
Total Costs	$217,416	$172,947	$186,451	$116,434	$82,189	$82,725	$83,231	$83,708	$84,840	$85,639	$86,439	$87,241
ANNUAL NET BENEFIT	($217,416)	($162,838)	($140,439)	($14,316)	$44,970	$59,337	$87,668	$123,527	$144,324	$146,303	$148,284	$150,326

OVERVIEW OF CASE ASSUMPTIONS

- Minimum tolerable willingness-to-pay (as measured by tariff level) with EIRR of 15% (tariffs can decrease by 21% from current levels).
- September 1995 tariffs applied in benefit calculations throughout life of project.
- No consumer surplus calculated in benefit calculations.
- Base case assumptions from ICF model: a) total output, b) portion which is substituted energy, c) portion which is incremental energy.

ECONOMIC BENEFIT CALCULATIONS	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
By Customer Category and By Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13
1 **Total Supplied (GWh) at the busbar (after 1.56% internal losses)**		0	0	305	3,267	6,537	7,002	7,002	7,002	7,002	7,002	7,002	7,002	7,002
2														
3 **Unserved Energy Before Losses (from ICF model)**		0	0	305	1,353	2,633	3,364	3,829	4,755	5,934	6,630	6,703	6,776	6,851
4														
5 **Substituted Energy (GWh) (line 1 minus line 3)**		0	0	0	1,914	3,904	3,638	3,173	2,247	1,068	372	299	226	151
6 Cost Savings ($/kWh) (See Economic Costs Calculations, Line:) 113		nm	nm	nm	0.00041	0.00347	0.00375	0.00394	0.00411	0.00427	0.00445	0.00451	0.00456	0.00462
7 **Value of Substituted Energy ($ '000)**		0	0	0	777	13,561	13,654	12,488	9,229	4,559	1,654	1,347	1,032	698
8														
9 **Incremental Energy Before Losses (line 1 minus line 5)**		0	0	305	1,353	2,633	3,364	3,829	4,755	5,934	6,630	6,703	6,776	6,851
10 Transmission/Distribution Loss 13%		0	0	40	176	342	437	498	618	771	862	871	881	891
11 **Incremental Energy After Losses**		0	0	265	1,177	2,291	2,927	3,331	4,137	5,163	5,768	5,832	5,895	5,960
12														
13 **Percentage Consumption by Classification**														
14 Industry	33.7%	34.8%	35.3%	36.3%	37.0%	37.7%	38.0%	38.3%	38.8%	39.2%	39.7%	39.9%	40.0%	40.2%
15 Agriculture	18.5%	18.3%	18.0%	17.9%	17.7%	17.4%	17.3%	17.1%	17.0%	16.9%	16.7%	16.8%	16.9%	16.9%
16 Transport	6.8%	6.9%	7.0%	7.2%	7.3%	7.5%	7.5%	7.6%	7.8%	7.9%	8.0%	8.0%	8.1%	8.1%
17 Residential/Other	41.0%	39.9%	39.6%	38.7%	38.0%	37.5%	37.2%	36.9%	36.5%	36.0%	35.6%	35.3%	35.0%	34.8%
18														
19 **Consumption by Classification (GWh)**														
20 Industry		0	0	96	436	863	1111	1276	1604	2024	2289	2324	2359	2396
21 Agriculture		0	0	47	208	399	507	571	704	872	966	980	993	1008
22 Transport		0	0	19	86	171	221	255	321	407	461	469	476	484
23 Residential/Other		0	0	103	447	858	1087	1229	1508	1860	2052	2059	2066	2073
24 Total Consumption		0	0	265	1,177	2,291	2,927	3,331	4,137	5,163	5,768	5,832	5,895	5,960
25														
26 **Tariff by Classification (Roubles)**	April '95	Sept. '95		Converted	April '95	Sept. '95	Avg. '95							
27 Industry	150	298		to 1995	0.0506	0.0694	0.0600							
28 Agriculture	101	260		Dollars	0.0341	0.0606	0.0473							
29 Transport	150	298			0.0506	0.0694	0.0600							
30 Residential/Other	36	84			0.0121	0.0196	0.0159							
31														
32 **PPP Ratio of Price Index (3 month average)**	(Feb-Apr)	(Aug-Oct)												
33 Industry	2,963	4,293												
34 Agriculture	2,963	4,293			Tariffs decrease by									
35 Transport	2,963	4,293			21% to yield EIRR of									
36 Residential/Other	2,963	4,293			15%									
37														
38 **Tariff by Classification (September 1995 Prices Used Throughout)**														
39 Industry	0.0545	0.0545	0.0545	0.0545	0.0545	0.0545	0.0545	0.0545	0.0545	0.0545	0.0545	0.0545	0.0545	0.0545
40 Agriculture	0.0476	0.0476	0.0476	0.0476	0.0476	0.0476	0.0476	0.0476	0.0476	0.0476	0.0476	0.0476	0.0476	0.0476
41 Transport	0.0545	0.0545	0.0545	0.0545	0.0545	0.0545	0.0545	0.0545	0.0545	0.0545	0.0545	0.0545	0.0545	0.0545
42 Residential/Other	0.0154	0.0154	0.0154	0.0154	0.0154	0.0154	0.0154	0.0154	0.0154	0.0154	0.0154	0.0154	0.0154	0.0154
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APPENDIX C

PRINCIPLES OF SHAREHOLDER'S AGREEMENT

Kuban GRES Co.

PRINCIPLES OF SHAREHOLDER'S AGREEMENT

1. Purpose of the Agreement

To form a venture leading to formation of a joint stock company registered under the applicable laws and regulations of the Russian Federation for the purpose of developing, obtaining financing required, constructing, owning and operating and maintaining power project(s) in the Northern Caucasus area of the Russian Federation. The power project(s) owned by the joint stock company will sell the electricity to the customer(s) under the terms of a long term Power Purchase Agreement with an intent to provide an adequate rate of return to the investors.

2. Definition of Shareholders

Shareholders shall be defined in three categories:

a) Founder Shareholders
b) Sponsor Shareholders
c) General Shareholders

Depending upon the category, the rights, privileges, responsibilities and liabilities of the shareholders shall be defined by this Agreement.

a) Founder Shareholder, are those listed in Annex A-1 who have founded this venture and are the initial signatory parties to this Agreement and jointly constitute the Group.

b) Sponsor Shareholders are those listed in Annex A-2 as modified from time to time and are the shareholders who have joined the Founder Shareholders in developing the project(s) prior to the financial close of the project.

c) General Shareholders are those who purchase shares through public offerings by the joint stock company or who purchase shares at the stock market once public trading of the shares have begun, or otherwise the shareholders who are not classified under categories a) and b) above.

3. Duties and Obligations of the Founder Shareholders

a) The Founder Shareholders shall commit the initial cash contributions per Annex B-1 of this Agreement, and revised from time to time through cash calls issued by the management of the Group -- or the joint stock company as required for the development of the project. Prior to or at the financial close as required by the

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lenders of the project, the Founder Shareholders shall contribute (and purchase the shares) the full amount of equity participation defined in Annex B-1 of this Agreement.

b) The Founder Shareholders agree to the management structure of the Group defined in Article --- during the development stage and the principles on which the management of the joint stock company listed in Article --- of this Agreement.

c) The Founder Shareholders, through the management structure, shall undertake to finance project(s). Towards this goal, the Group shall commit to support Feasibility Report(s) efforts for the project. The Group shall follow the recommendations of such study or studies that directly influence financing of the project(s).

d) The Founder Shareholders, through the management structure, shall support all efforts towards raising financing of the project. To this end, the Group may invite additional equity participants, defined as Sponsor Shareholders, under the provisions of this Agreement, and additional terms to be negotiated with potential participants.

e) The Founder Shareholders through the management structure, shall support all efforts to raise the debt financing for the project(s). The Group shall appoint Consultant(s) or cause to have Consultant(s) appointed to assist in raising debt financing and negotiate the terms and conditions of the loan.

f) The Group shall meet from time to time to vote on key issues as requested by the appointed management of the Group, but not less than once a month on a mutually agreed date and location.

g) The Founder Shareholders recognize that certain Founder Shareholders may have agreements to provide goods and services to the project(s) or may have agreements to purchase electricity or other products from the project(s). Notwithstanding such other agreements, the Founder Shareholders shall support the project(s) in the best interest of all shareholders whether Founder Shareholders, Sponsor Shareholders or General Shareholders. The Founder Shareholders pledge to support the interest of the project(s) being undertaken by the Group and shall abide by all the decisions made jointly and adopted through the appropriate voting mechanism provided in this Agreement.

h) The Founder Shareholders shall nominate one representative each and one alternate representative. The representative shall attend all meetings called by the Managing Director of the Group and render his vote on key issues. The alternate representative shall attend the meeting in the event the representative is not available. The nominations shall be in writing from the appropriate authorities of the companies.

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i) The Founder Shareholders along with the Sponsor Shareholders shall appoint the key members of the organization reflected in Annex ---. The key members shall be performed to the set of guidelines to be developed by the Group. The key members may engage the support staff authorized by the Group.

j) As soon as practical and taking into consideration the time required for the procedures, the Founder Shareholders shall form a joint-stock company (Project Company) for the project implementation. Upon proper registration of the Project Company all the rights, privileges of the shareholders of record at that time, will be governed by the rules and charter of the Project Company. A Novation Agreement shall be prepared and properly executed.

4. **Equity Participation**

a) The Shareholders recognize that certain funds have been expended by some members of the Founder Shareholders towards the development of the project and towards the construction of the project. An audited report of these costs is available for review. The Founder Shareholders who have utilized their funds in meeting these costs shall be entitled to recover these costs at the financial close for the project in the following manner:

- The funds (in cash) expended for the development of the project shall be reimbursed in equivalent shares of the Project Company at -------- times the par value for such shares. [For the purpose of calculating present day cost for the funds utilized in previous years (after June 30, 1993) the equivalent US dollar conversion rate prevailing at the time of the actual expenditure have been used.]

- The funds (in cash) expended for the construction of the project shall be reimbursed in equivalent shares of the Project Company at the par value for the shares;

b) The funds (in cash) spent by the Group (and Sponsor Shareholders) after this Agreement has been executed and comes into effect, towards the development cost of the project, shall be reimbursed in equivalent shares of the Project Company at ------ times the par value for such shares;

c) The funds (in cash) spent by the Group (and Sponsor Shareholders) and duly approved by all of the shareholders towards construction of the project shall be reimbursed in equivalent shares of the Project Company at par value of such shares;

d) The Founder and Sponsor Shareholders shall provide the equity contribution to the Escrow Account, in cash, prior the financial close of the project. Failure to meet these requirements by the specified date shall result in forfeiture of the right to acquire the shares and may further result in liabilities to the other Founder and Sponsor Shareholders;

e) All cash call requests made by the management of the Group, duly made in writing shall be honored by the Founder and Sponsor Shareholders by the date specified in such request. Failure to meet the cash call may result in suspension of the shareholder in further participation in equity. The shareholder in question shall be entitled to receive shares in accordance with this Agreement, at financial close for the contribution made prior to the suspension;

f) The shareholders, prior to financial close of the project, may contribute part of their equity in kind, by providing certain services provided that such in kind contributions do not exceed --------% of the total equity participation committed by the shareholder. The shareholders shall receive equivalent shares of the Project Company at par value for the agreed upon value of such services duly certified by the shareholders company and audited, at the financial close of the project.

g) Each of the shareholders, Founder and Sponsor, shall receive vouchers stating the number of shares to be allocated to the shareholder when the cash calls have been specified on or before the due date. These vouchers shall be exchanged for the shares in the Project Company at the time determined by the Chairman of the Group, after the Project Company has been duly registered but prior to the financial close for the project. All taxes (and expenses) levied during the exchange of the vouchers for shares shall be paid by the Project Company.

h) Founder and Sponsor Shareholders commit that for at least three years after the date the project has been declared ready for Commercial Operation, they will continue to hold their shareholding in the Project Company or otherwise as required by the Lenders. After the said three years, they may retain the shares or sell the shares on the stock exchange.

Unless required by law, new or in existence such shareholding is necessary for the stability of the Project Company and the shareholders shall notify this intent to other Founder and Sponsor shareholders, in writing, at least 60 days before the date of sale of the shares.

i) The contribution to the equity for the purpose of development of the project shall be in direct proportion to the percentage of equity participation committed for the Project Company. All cash calls shall be in the same proportion

5. **Sponsor Shareholders**

Upon Founder Shareholders' acceptance, the Sponsor Shareholder(s) will be invited to join the Group. The terms of joining the Group and subsequently receiving vouchers (and shares in the Project Company when due) shall be specified in the Sponsor Shareholder Agreement which shall become part of this Agreement. The terms of the Sponsor Shareholder Agreement will clarify the rights liabilities and representation by the Sponsor Shareholder.

6. **Management Structure**

a) Each shareholder of the Group shall be entitled to nominate one representative and one alternate representative. The representative will be named Director of the Group. The alternate representative will be the Alternate Director.

b) The Directors will elect a Chairman who shall be authorized to act on behalf of the Group, except in signing the Security Package documents. The Security Package documents shall be signed by the Chairman, the Managing Director and the Chief Financial Officer for the Group.

c) The Directors will elect a Managing Director, who shall be charged with day to day affairs of the Group. Managing Director's authorities shall be described in the procedures for working of the Group.

d) The Directors will elect a Chief Financial Officer who shall be responsible for all funds of the Group, maintaining auditable accounts for the Group, meeting the financial obligations of the Group, preparing budgets and issuing cash calls as required to the shareholders. All disbursement will require at least two signatures.

e) The Managing Director, with approval from the Chairman, shall propose a staffing plan consistent with the organization chart provided in Appendix ----- to this Agreement.

f) The Board of Directors shall meet as requested by the Chairman, in writing, but at least once a month to discuss and vote on the proposed issues.

g) A minimum of two thirds of the Directors (or Alternate Directors) must be present for any official transaction and voting.

h) Each Director shall have right to cast his vote in direct proportion to the number of shares represented by him.

i) The Directors, at the initial meeting, will finalize as to which issues require unanimous approval and which require majority voting based upon the following principles:

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- Decision to abandon the efforts on the project shall require unanimous approval. Also to undertake any activity not related to the project and that requires substantial expenditures will require unanimous approval.

- Any decision that may result in diluting the equity holding of a shareholder shall require unanimous approval.

- Cash call approval shall require majority vote.

- Introduction of a Sponsor Shareholder shall require majority vote.

- Novation of Group's rights to the Project Company shall require majority vote.

j) Once the Project Company has been duly registered, the Management of the Group shall gradually transfer all responsibilities in connection with the Project to the Management of the Project Company.

k) Upon Novation Agreement transferring the rights and obligations of the Group to the Project Company, or soon thereafter as practical, the Group will cease to function and a resolution based on majority vote shall be approved dissolving the Group.

l) The Directors, in conjunction with the Management of the Group shall form committees to finalize the Project Agreements and the rest of the Security Package documents through negotiations with the respective paties. Selection of such committee members shall be such that no conflict of interest situation arises within the Group.

m) In the event a Founder or Sponsor Shareholder notifies, in writing, his desire to withdraw from the Group, such withdrawal shall be considered effective as of 30 days from the date of the notice. The equity participation of the withdrawing shareholder shall be allocated in the following order:

    i) All remaining shareholders may subscribe to the available allocation in direct proportion of their commitments based upon discounting the withdrawing shareholders portion;

    ii) The unclaimed portion of the available equity proportion may be purchased by one of the shareholders;

    iii) A new Sponsor Shareholder may be invited to take over all or the available part of the equity interest.

Upon proper reallocation of the shares, the withdrawing shareholder will no longer be required to honour any cash calls. The withdrawing shareholder shall receive shares in the Project Company or cash payment for the vouchers held by him, at the Financial Close of the Project. In the event the Project fails to achieve Financial Close or otherwise has been abandoned through appropriate voting by the Directors, the Group shall have no liability to reimburse the withdrawing shareholder.

Upon such withdrawal from the Group, the Director representing the withdrawing shareholder shall tender his resignation to the Group along with the Alternate Director.

7. **The Project Company**

a) The Group will initiate and finalize the registration of the Project Company in accordance with laws and regulations of the Russian Federation. The Group will also assure proper registration with respect to the local and regional requirements.

b) The Project Company shall be organized with 12 Directors and in accordance with the chart(s) in Appendix ---- of this Agreement.

c) The Founder and the Sponsor shareholders may designate the number of Directors, (for the initial three years as defined herein) as follows:

Percentage of Equity Contributions	Member of Directors
40 - 50	5
30 - 40	4
20 - 30	3
10 - 20	2
5 - 10	1
less than 5	0

The shareholders may, in writing, give up their privileges of such nominations in favor of the shareholders of the Group, thereby enhancing the gaining (favoured) shareholders rights to nominate Directors.

The total number of Directors in the Project Company shall be 12. The balance of the Directors shall be elected by the General Shareholders at the first meeting of all shareholders. The Group Shareholders shall have the right to nominate the Directors, as provided above for three years after the project has achieved Commercial Operations. After the three years, all Directors shall be elected by all shareholders, except the shareholder having the majority of the shares or otherwise

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representing majority of the shares, shall have continuing right to nominate five Directors.

The Group Shareholders may nominate the same Director for the Group and the Project Company, except those Directors of the Group who are elected as the Chairman, the Managing Director or the Chief Financial Officer may not be nominated as the Directors of the Project Company, so long as the Group is a functioning entity.

d) The Directors of the Project Company shall elect a Chairman. Each Director shall represent one vote for all resolutions. The Chairman in conjunction with the Directors shall appoint a President, Financial Officer and Vice President, Manager of Technical Affairs, Manager of Construction, Operation and Maintenance and a Manager of Procurement. The compensations and the benefits for these positions and other salaried positions shall be set as requirements and guidelines by a committee, organized by the Directors. The compensation and benefits package and the key position nominees shall be approved by the Directors.

e) All meetings of Directors shall be considered to be official with business transacted and duly voted provided that at least 70% of the Directors are present. In absence of the Chairman, the convening Directors may elect a Chairman for that meeting. All decisions shall be made by the majority voting in favour.

f) The Directors shall set the number of shares and its par value and authorized issue of the shares in the following order:

  i) The shares shall be issued against the vouchers held by the Group Shareholders.

  ii) The shares shall be issued to the Group shareholders in the proportion of their equity commitments and upon receiving the payments for such commitments in the specified Escrow Account.

  iii) At least 20% of the shares shall be offered (through an underwriter) to the public in accordance with the rules of the stock market.

  iv) Failing the ability to sell the shares to the public due to unavailability of buyers, the Group members will be offered to purchase these shares. Any unclaimed shares shall be purchased by the majority shareholder from the Group, provided that the equity requirements to the extent specified, is a necessity.

g) The Project Company shall undertake all rights and obligations of the Group Shareholders upon appropriate Novation Agreement. The Project Company shall

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specifically adopt its charter and procedures to protect the inherent rights of the Group Shareholders specified in this Agreement.

h) The Directors shall declare dividends to the shareholders with the respect to the profit and available cash and in accordance with the debt finance agreements of the Project.

8. General Provisions

a) Each shareholder, Founder or Sponsor, represents and warrants to other shareholders that at the date of executing this Agreement:

   i) The shareholder is the legal entity duly registered as represented herein in accordance with all applicable laws and regulations of the Russian Federation.

   ii) The shareholder has the means and capability to meet the financial obligations undertaken by it, under this Agreement.

   iii) The appropriate legal authorizations have been obtained from its own company to participate in the Project to the extent specified in this Agreement.

b) Each shareholder, Founder or Sponsor, shall provide all information that is known to it, in connection with the Project, or which may have bearing on the Project.

c) This Agreement may be terminated by unanimous vote of all shareholders without any liabilities to each other, except those agreed upon. In the event an unanimous vote is not reached, the shareholders willing to continue with the Agreement shall treat the other shareholders in accordance with the withdrawing shareholders provisions of this Agreement.

d) The withdrawing shareholders, under any circumstances, shall be required to submit all documents and provide all information in connection with the Project, to the remaining shareholders of the Group, except for the vouchers that have been issued to it.

e) The Founder and Sponsor Shareholders shall observe strict confidentiality with respect to the information pertaining- to the Project. No shareholder may disseminate information, especially that specified as being "sensitive" or "confidential" except as authorized for limited purpose as authorized by the Chairman.

f) The rights and liabilities under this Agreement may not be transferred or assigned by any shareholder without the consent of the Group.

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g) The rights and obligations of the shareholders under this Agreement shall be several and not joint nor joint and several.

h) No shareholder, without appropriate Directors resolutions, shall commit the Group or make commitment on behalf of the Group. In the event, such unauthorized commitment is made by any shareholder, the shareholders shall not be obligated to honour the same.

i) All shareholders agree that this Agreement and duly approved amendment thereof by the way of Appendices, is the only document that governs the relationship between the shareholders in connection with this Project.

j) This Agreement shall be governed by and construed in accordance with the laws of the Russian Federation. Any dispute arising from this Agreement shall be resolved with binding effect on the shareholders, in accordance with the Arbitration Rules of -------

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APPENDIX D

POWER PURCHASE AGREEMENT

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PRINCIPLES OF THE POWER PURCHASE AGREEMENT*

By and Between

KubanGRES Co.

and

RAO EES Rossii

* Principles recommended by Consultants, currently undergoing review by all parties

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POWER PURCHASE AGREEMENT OUTLINE

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SCHEDULES

1.0 INTRODUCTORY STATEMENTS

This first article of the Power Purchase Agreement (Agreement) identifies RAO EES Rossi (RAO) and the Project Company Kuban GRES (the Company) as the contracting parties and shall state that, under this Agreement, the electrical energy generated by the Plant shall be sold to RAO by the Company. This section may state in the form of "whereas" clauses all the steps the parties have accomplished or intend to take upon signing the Agreement.

2.0 DEFINITIONS

2.1 Defined terms shall be provided for convenience and to be precise without repetition in the contract wording. Defined terms are limited only by the desires of the contracting parties.

2.2 The following words and expressions shall have the following meanings:

- "Agreement(s)" - means the contracts and documents between the Project Company and RAO or third parties.

- "Approved" or "Approval" - means approved by or approval of RAO unless otherwise stated. All approvals shall be in writing.

- "Calendar Day" or "Days" - means consecutive days, including weekends and Holidays.

- "Capacity Charges" - means a specific component of Tariff which the Project Company is entitled to receive upon the start of Commercial Operation.

- "Commercial Operation" - shall mean that the Completion Certificate for the Project has been issued and the Project Company is entitled to receive payment for the Capacity Charges defined under the Agreement.

- "Completion Certificate" - means the certificate to be issued and signed by RAO or its representative and delivered to the Project Company signifying satisfactory completion of the construction phase of the Project, completion of performance testing, and the beginning of plant operations. Upon issuance of the completion certificate, the Project is deemed ready for commercial operations and the Project Company is entitled to receive payment for the capacity charges defined under the Agreement.

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- "Construction Equipment" - means all appliances or things of whatsoever nature required in or about the execution, completion, maintenance or operation of the works, but does not include permanent plant or other items intended to form or forming part of the works.

- "Contractor(s)" - means any person, firm or firms, company or companies under contract to the Project Company to perform work on or supply goods for the Project.

- “Despatch” - The instructions issued by RAO from the Despatch Center in accordance with this Agreement for the Company to schedule and control the generation of the units prior to the Commercial Operation date and the Plant thereafter in order to increase or decrease the electricity delivered to the RAO grid system.

- “Despatch Center” - RAO’s system control center located in [LATER] designated by RAO from time to time from which RAO shall Despatch the Plant.

- "Drawing" - means collectively, all the drawings listed in the Agreements and also such supplementary drawings as the Project Company will issue from time to time. The word drawings shall also be understood to include documents such as procedures and manuals.

- “Energy Charge” - means the price paid by RAO to the Project Company for Net Energy Output as adjusted from time to time in accordance with this Agreement.

- "Financial Close" - means the execution of the financial agreements between the Project Company and its lenders. Specifying the terms and conditions and the durations of the financing. Financial Close shall also mean that certain conditions precedent to the availability of funds has been fulfilled and the Project Company has received commitments for the required equity.

- “Force Majeure” - means an event or occurrence specified in this Agreement.

- “Forced Outage” - An interruption of a unit’s generating capability that is not the result of (i) a request by RAO in accordance with this Agreement; (ii) a Scheduled Outage; or (iii) an event or occurrence of Force Majeure.

- "Government" - means the Government of Russia, represented by various officially appointed Ministries or Agencies.
- "Guaranteed Net Output" - means the total output of the Plant at ISO less the agreed upon auxiliary power (or heat) consumption at the Plant.
- "Interconnection Facilities" - All the facilities on the high side of the step-up transformer described in Schedule 3 to be constructed by or for RAO to enable it to receive and deliver capacity and energy in accordance with this Agreement plus the Metering System.
- "Operating Committee" - means the committee established for the purpose of determining operating standards and procedures for the Plant.
- "Plant" - means the generating plant including all auxiliaries and support facilities including the switchyard located in the Village of Mostovskoy in Russia.
- "Project Company" - means the Russian Joint Stock Company Kuban GRES established by a group to undertake the Project activities in accordance with the Agreements.
- "Project Schedule" - means Project Company's schedule agreed to by RAO to meet the completion milestone dates as specified in the Agreements.
- "Project" - means the combined cycle thermal power station Kuban GRES located in the Village Mostovskoy of Krasnodar Krai with related interconnection facilities, which are to be supplied by the Project Company on a Build, Own, Operate and [possible] Transfer (BOOT) basis and known as the Krasnodar Power Project.
- "RAO" - means the Russian Joint-Stock company of power sector and electrification, which owns and operates the Unified Power System.
- "RAO Gasprom" - means the Russian Joint Stock Company Gasprom which owns and operates Russia's natural gas transmission and distribution

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networks, and in this context includes Kuban Gasprom.

- "RAO Grid System" - means Interconnection Facilities and any other transmission or distribution facilities on RAO's side of the interconnection point(s) through which the net energy output of the Plant will be distributed by RAO to users of electricity.

- "Reactive Power" - means the wattless component of the product of voltage and current, which the units or the Plant shall provide to or absord from the RAO Grid System and which is measured in MVAR.

- "Scheduled Outage" - means a planned interruption of a unit's or the Plant's generating capability that (i) is not a maintenance outage; (ii) has been scheduled and allowed by RAO; and (iii) is for inspection, testing, preventive maintenance, corrective maintenance or improvement.

- "Site or Jobsite" - means the land and other places provided by the Krasnodar Krai and Mostovskoy Administrations on, under, or through which the Project is constructed and the work is executed or carried out, and any other lands or places provided by RAO for the purpose of the Agreements, together with such other places as maybe specifically designated in the Agreements as forming part of the Site or Jobsite.

- "Tariff" means the agreed upon payments by RAO to the Project Company under the Power Purchase Agreement.

2.3 Singular and Plural

Words importing the singular only also include the plural and vice versa where the context requires.

3.0 TERM OF AGREEMENT

3.1 The term of this Agreement begins at the effective date of the Agreement and ends after a period of 30 years. The provisions applicable to the operation of the Plant shall become effective when the construction of the Plant has been completed and the Completion Certificate has been issued. The construction period shall accomodate the commissioning schedule agreed to in Schedule 1.

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3.2 In the event the construction period exceeds the schedule identified in Schedule 1, RAO may consider an extension of the period for the Agreement,such that the Agreement will have an effective life of 30 years from the date the Completion Certificate was issued. Extension of the Agreement period will not relieve the Company of any penalties for delay or other action that RAO may be entitled to, per the Agreement.

3.3 A non-binding option will be included for extension of the Agreement. The procedures and their timing shall be set forth in order that any agreed upon extension will be determined two (2) years before the expiration of the Agreement.

3.4 Another matter which should be given consideration in the Agreement is the disposition of the generating facilities upon contract termination. RAO may desire an option to acquire the Company's facilities upon termination. If the parties agree to include such an option, the procedures and timing and possibly some of the terms of acquisition should be set forth in order that if the option is exercised, all the terms and conditions of acquisition can be determined and agreed prior to termination of the Agreement. The parties shall agree on the disposition of the facility prior to the execution of the PPA.

4.0 PROJECT FACILITIES

4.1 The Company is obligated under the Power Purchase Agreement (PPA) to design and construct the Plant and Interconnection Facilities to meet the specifications in Schedule 1. RAO will be given the right of access to inspect the Project Facilities during construction and installation as well as during all repairs, replacement or maintenance activities following initial operation.

4.2 The Company shall use the metric system of measurement for all designs, plans and drawings.

4.3 The design and construction of the Project Facilities shall be in accordance with Russian Federation codes and standards or equivalent international codes and standards and shall be referenced in the Agreement. Subsequent changes to these codes and standards shall be agreed between the parties.

4.4 RAO will have the right to review the qualifications of contractors engaged by Company, but can not unreasonably withold its consent unless it can demonstrate deficiency of proposed contractors.

5.0 COMPANY'S REPORTS DURING CONSTRUCTION

5.1 The Company shall be required to prepare and submit the following reports during the construction phase.

A. Imported shipments report

The Company shall prepare and keep on file for RAO's review, a quarterly report of imported shipments of the Plant.

B. Plant fabrication and shipping progress report

The Company shall, within thirty (30) Calendar Days after Financial Close, and monthly thereafter, submit to RAO a Plant fabrication and shipping progress report.

This report shall track the progress status against the planned schedule, of all major Plant equipment and Construction Equipment to be procured by the Company, including that of Contractor's material and equipment.

C. Monthly progress report

During the duration of the construction phase, the Company shall submit to RAO a monthly progress report. Such report shall include a narrative summary of the construction history to date, including description of progress achieved, list of significant milestone events accomplished and related dates.

D. Critical items report

The Company shall, within thirty (30) Calendar Days after the Financial Close, initiate a critical items report which will indicate those activities which are currently behind schedule and will highlight activities that have the potential of affecting the schedule.

The report will include the corrective action required and the responsible party for such action. The report will be updated, issued as required and summarized in the monthly progress report.

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E. Quality surveillance report

The Company shall prepare and keep on record a monthly quality surveillance report implementing the Company's quality surveillance/audit program to verify that the Contractors and the subcontractors furnishing the Plant are meeting the quality requirements stated in the specifications.

F. Final report

The Company shall prepare and keep on record a final report with detailed cost breakdown for the construction phase and summarize on a monthly time scale all the construction activities and previously submitted reports.

6.0 TESTING

6.1 The Agreement will describe the detailed procedures for testing of the Project Facilities based upon international codes and standards and the specifications of the Project. The Agreement will require the following Performance Tests to be successfully carried out prior to issuance of the Completion Certificate, Initial Performance Test:

- Net plant output of 900 MW at full capacity upon erection and commissioning of all units, and staged output as indicated in Schedule 1, adjusted for ambient site conditions and fuel characteristics, as applicable.

- Net plant heat rate at Net plant output as guaranteed by the Company.

- Reliability of the plant demonstrated by a continuous operation of not less than five (5) Calendar Days. Appropriate adjustments such as for protective relays etc. shall be deemed to have been completed prior to the reliability run.

- Interconnection Facilities testing.

- Testing of the communication facilities between the Plant and the Despatch Center.

6.2 The Company shall be prohibited from connecting the Plant to RAO's system until RAO gives approval through proper notice to do so pursuant to satisfactory

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completion of inspections and tests of certain Interconnection Facilities and of pre-connection tests of the equipment.

6.3 The Agreement shall state the time limits, as necessary, for exchange of information, developing rules and procedures, commenting and agreement of the parties. Adequate notice provisions for dates of tests and opportunities for appropriate personnel to be present and to receive and review test data should be provided.

6.4 Provisions also should be made for timely resolution of any test disputes in order that remedies be effected for any deficient facilities and that conforming facilities be approved for operation as expeditiously as possible.

7.0 COMPLETION AND INITIAL OPERATION

7.1 Operations will commence when all tests are satisfactorily completed and RAO issues a Completion Certificate. The date of commencement shall be the date when the operative provisions of the Agreement become effective. It also determines the termination date of the Agreement.

7.2 The required date for completion, testing and commercial operation of the plant shall be in accordance to the timetable in Schedule 1, with penalties for delays beyond ninety (90) Calendar Days from that date. The project company shall be liable for payment of penalties in the amount of [LATER] per KW capacity shortfall per day for each day or part day of delay after the ninety (90) Calendar Day period, unless and to the extent such delays are due to Force Majeure Events or the acts or omissions of RAO.

8.0 PENALTIES FOR FAILURE TO MEET GUARANTEED OUTPUT DURING INITIAL PERFORMANCE TEST

8.1 The Parties acknowledge that failure of the Company to deliver at the time of the initial performance tests, the agreed upon Guaranteed Net Output at one hundred percent (100%) load as measured at the high side of the main step-up transformer will be cause for a one time penalty. The Parties agree that the Company shall pay to RAO as a penalty, a sum of (LATER) per kW based on the difference between the Guaranteed Net Output and the actual net output. In addition, if the Company fails to meet a ninety-five percent (95%) of Guaranteed Net Output for the plant, RAO reserves the right to reduce the capacity charge payable to the Company by a proportionate amount.

The net output established during the initial performance testing, if different from the Guaranteed Net Output, will become the new unit rating and will become the basis for performance measurements during the Plant operations.

The appropriate adjustments for ambient conditions versus the agreed upon operating conditions and due to heating values of the fuel shall be made to arrive at the actual electrical output.

In the event the plant fails to meet the Guaranteed Net Output after the first performance testing, the Company will have ninety (90) Calendar Days to make appropriate modifications and repeat the Performance Test to demonstrate the compliance with the guarantees. Failure to achieve the Guaranteed Net Output at the repeat tests during the ninety (90) Calendar Days, will result in the assessment of the penalties stipulated above.

8.2 Notwithstanding the provisions stated above, if the plant fails to achieve 90% of the Guaranteed Net Output at the repeat performance test, the Company shall be required upon commissioning to make good the deficiency in the net output capacity of the whole Plant up to the amount of 900MW or continue to pay penalties identified in 8.1. Such making good shall not entitle the Company to any increase in the tariff which would have ruled had the above provisions been met.

The Company shall submit their plan for such making good to RAO within 45 days from the repeat performance test. In the event the plan is not submitted to RAO by the forty-fifth day, RAO reserves the right to defer any payments due to the Company under the Fixed Capacity Charge for the Plant component of the tariff until receipt of the plan.

9.0 ENERGY DELIVERY AND SCHEDULING

9.1 Delivery

9.1.1 The point of delivery of the electrical energy purchase and sale will be at the high voltage side of the station step-up transformers. Such a point of delivery also eliminates the need to determine the station uses under the Agreement. This means that generating capacity determinations will be net capacity at delivery rather than gross capacity before deducting station uses. The Company retains title to and accepts all responsibility for electrical power on the generating side of the point of delivery and RAO on the other side of the point of delivery.

9.1.2 The Company shall have no claim, other than the capacity charge, if RAO can not receive energy in accordance with the mutually agreed energy delivery schedules due to an outage of the transmission lines from the time at which RAO informs the Company of such outage.

9.2 Scheduling

Preliminary scheduling of thermal and electrical power delivery shall be on an annual basis for planning and budgeting purposes by both parties. The proposed schedule will be initiated by RAO for review by the Company sixty (60) Calendar Days before the year begins for timely exchange of information and comments. The schedule may be based upon historical record of the load demand for the previous year, with appropriate adjustment factor for the increase in demand for the coming year. Similarly the planned maintenance scheduling shall be in parallel with the preliminary delivery schedule, with the Company specifying the amount of time needed for planned maintenance for each generating set and the preferred sequencing. RAO shall have the right to specify the months during the year when the planned maintenance may be scheduled.

A monthly schedule of hourly delivery and spinning reserve requirements is provided by RAO prior to the beginning of each month. RAO will have flexibility to modify this schedule each day prior to the day of delivery because of unanticipated load demands or availability of other generating resources.

The Company will exercise best efforts to supply the hourly schedule energy delivery and spinning reserve. However, in the event of a forced outage or partial outage the Company promptly notifies RAO and is relieved of the delivery obligation to the extent of the magnitude and duration of the outage.

RAO takes delivery of the energy as scheduled, except during emergency conditions on the system. Upon notice, including through automatic dispatch if provided, RAO immediately may reduce schedule energy delivery during emergency conditions or increase delivery to the extent spinning reserve has been scheduled.

10.0 FUEL

10.1 Fuel Supply

The natural gas for Plant startup, commissioning and operation will be supplied at the Site by RAO Gasprom, pursuant to the Fuel Supply Agreement, with full reimbursement of fuel costs by RAO for the term of this Agreement. A pressure reducing (or increasing) terminal for the gas supply will be built onsite by the Company and the Company will be required to connect [LATER] meters outside the boundary of the terminal for the Plant gas supply.

In the event of fuel interruptions to the plant resulting from a default on the part of RAO Gasprom, RAO will continue to make capacity payments to the Company.

10.2 Fuel Quality

RAO Gasprom, under a separate Fuel Supply Agreement will supply natural gas to the Company in accordance with the gas quality specification as contained in Schedule 1.

10.3 Backup Fuel

The Company shall provide for storage facilities for liquid fuel at the site. All quantities of liquid fuel shall be provided and paid for by the Company at prevailing market prices. On the Commercial Operation Date, the Company shall have available at Jobsite, full quantity of liquid fuel in the tanks, at its cost. Should the supply of fuel gas be interrupted, the Company shall operate the Plant with liquid fuel except the Company shall have no obligation to use the liquid fuel for more than eight [8] Days in the event that the liquid fuel is not delivered to the Plant. The Energy Charge to be paid by RAO to the Company under such conditions shall be adjusted. If the Company utilizes liquid fuel during such an interruption for the operation of the Plant, it shall as soon as practicable ensure that the levels of liquid fuel are replenished and maintained. The supply of liquid fuel for testing purposes shall be the responsibility of, and at the cost of, the Company.

11.0 PRICE FOR ENERGY

11.1 Tariff

All transactions between the parties for the sale and purchase of energy will be denominated in domestic Russian currency. The Tariff to be paid to the Company by RAO under the Agreement will include the following components:

A) The Fixed Capacity Charge Component (fixed monthly charge payable to the Company upon maintenance of efficiency and availability requirements indicated in the PPA):

Debt service indexed to the currency of the loan,,

Fixed maintenance costs, based on agreed upon standards for expenditure,

Target rate of return of [later]% on equity capital, indexed to currency exchange rate,

Other fixed costs, including insurance (see section 23.5), property taxes, permitting fees, payments for government guarantees, and other taxes and duties.

B) Energy Charge Component (charge per KWh based on plant despatch)

Cost of fuel, allowing a pass-through of all fuel costs incurred to meet dispatch requirements, (price of fuel x planned heat rate)

Variable O&M costs, allowing for recovery of all variable operations and maintenance costs incurred to meet dispatch and capacity requirements, based on agreed upon standards for expenditure,

Extra Profit component, to provide incentives for the operation of the plant with maximum efficiency, determined as:

a) Bonus: [later]% of demonstrated savings through efficiency improvements under a regulated tariff, or
b) Equivalent of [Bid Price - Variable Cost], in a situation of competitively bid energy tariff.

Other fees, to ensure recovery of all costs incurred in response to the dispatcher's requirements of the plant, including payments for:

A. Spinning Reserve

There is an added cost for fuel and operation and maintenance for providing spinning reserve. A clause in the Agreement shall address this issue.

B. Reactive Power

The Agreement shall stipulate the margins for reactive power and adjustments provided in case these limits are exceeded. Reactive power during operation increases electricity losses and decrease the maximum productive capacity of the generators.

C. Frequent Starts

There is a cost in shutting down and starting up units. The cost of expected starts shall be included in determining the initial base energy price and price adjustment provided for increased frequency of starts due to system requirements.

D. Operating Regime

Should the ambient temperatures during the year be higher than those agreed upon as the basis of the performance of the Plant, the output and the heat rates for the unit may be affected. This may result in higher fuel consumption and/or lower output. The Agreement will recognize the higher fuel costs adequately justified by the Company. Additional costs for fuel shall not become payable, unless justified by the Company and agreed by RAO.

11.2 Penalties during Ongoing Plant Operation

11.2.1 Penalties Payable by RAO

Under the proposed Agreement, RAO is bound to pay the Capacity Charge for the investment, regardless of energy used. This capacity charge is also payable in case of plant unavailability resulting directly from fuel supply interruptions, which are considered in this agreement as a force majeure event.

In the event of a default or delay in payment of either a planned capacity charge or energy consumed, RAO is liable to pay the Project Company the amount due plus a penalty equivalent of [later]% of the balance due per day of payment delay. In such an event, Project Company may cease compliance with Despatch Requirements until all payments are made in full. During such period until resumption of normal operations and payments, RAO would be liable for full payments of the capacity charge.

11.2.2 Penalties Payable by Project Company

The Agreement will also provide for the collection of penalties by RAO for failure to perform, as described below:

The Plant will be subject to periodic testing during Plant operation, based upon a mutually agreed testing schedule. In the event that the Plant fails to deliver its rated capacity, during any of the periodic testing, a penalty of [LATER] per kW of shortfall will be applied for each twelve (12) month period that the shortfall exists.

The Company may request a follow up test to demonstrate that the Plant is capable of providing the Guaranteed Net Output. The successful test that demonstrates that the plant is capable of producing the Guaranteed Net Output will not relieve the Company from its obligation to pay the stated penalty until that test. A new period of the said twelve months (12) will begin from the date of successful testing. Should the test demonstrate only a partially successful result where the actual net output has improved from the first test, but not to the extent that it meets the Guaranteed Net Output, the test shall not be given further consideration.

Penalties imposed on the project company for not meeting availability and performance requirements defined in the PPA would not be included in pass-through costs.

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11.2.2 Price of Energy Generated During Start-Up

While the Plant is being tested and before the Completion Certificate is issued in accordance with the Agreement, there will be a certain quantity of energy produced during those tests. The price for this energy will be the energy charge.

12.0 TARIFF ADJUSTMENTS RELATED TO COST

It will be necessary to specify in the Agreement which components of the energy price are subject to adjustment and what changed conditions would merit adjusting the price.

Some elements of fixed costs represented in the tariff will be adjusted as well as variable costs. The tariff will be adjusted every month on the following basis:

Fixed Capacity Charge Component:

1) Debt service for foreign currency debt approved for the capital structure of the Company will be indexed to the currency of the debt,

2) For fixed maintenance costs, ruble expenses will be indexed to Russian inflation, and hard currency components indexed to the exchange rate and international inflation applicable to the O&M costs,

3) Allowed rate of return on equity, indexed to the currency exchange rate, with a provision of adjustment to changes in tax regulations and other change of law and state regulation affecting investor profits,

4) Other fixed costs, including changes in insurance, property taxes, permitting fees, payments for government guarantees, and other taxes and duties, with indexation to foreign currency exchange rates for hard currency costs.

Energy Charge Component:

1) Cost of fuel would be adjusted to allow a pass-through of all fuel costs incurred to meet dispatch requirements,

2) Variable O&M costs, allowing for recovery of all variable operations and maintenance costs, incurred to meet dispatch and capacity requirements, with adjustments in the necessary ruble payments to cover hard currency costs,

3) Extra Profit component, indexed to ruble inflation but not currency exchange rates,

4) Other fees, would be adjusted as necessary to allow full recovery of costs, whether in domestic or foreign currency.

13.0 PAYMENT AND BILLING

The billing procedures will be designed to track the pricing provisions, the adjustments in prices and the reductions in price related to performance, including all supporting computations each month.

13.1 Computation of Bills

Monthly billing includes the following data and computations:

i. Energy delivered each hour of the month
ii. Computation of monthly Plant capacity payments (Fixed and Variable)
iii. As defined in "Cost of Fuel" in Section 11.0
iv. Computation of energy charge payment net of fuel costs
v. Computation of performance penalty
vi. Computation of price adjustments, if any.

13.2 Payment Procedure

At the outset of each monthly billing period, a tariff forecast shall be developed by the parties based on a forecasted increase in tariff adjustment indexes identified in 12.0, whereby the forecasted indexes for a given month shall be no less than the actual indices of the previous month. RAO shall make payments based on the calculated indices and estimated energy purchases into a special escrow account. Upon issuance of a bill by the Project Company, the bill will be reconciled with payments to the account with additional payments to the Project Company by RAO or a credit issued by the Project Company to the account for corresponding under or over-payments by RAO to the account.

13.3 Notices

The Agreement should specify the maximum number of days after the month ends that the Company shall submit the billing computations to RAO. It will set a limit in number of days following receipt of the bill that RAO has to inform the Company

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of a billing error. The method and place of payment and the due date will be clearly set forth.

14.0 INTERCONNECTION AND COMMUNICATION FACILITIES

It will be necessary for the parties to coordinate closely in the planning, design and inspection of electrical interconnecting and communication facilities. The facilities installed by the Company must be compatible with and meet RAO's system needs.

14.1 Transmission and Switchyard

The Agreement will require KubanGRES Co. to design, construct, maintain and operate the connecting transmission, transformation and switchyard facilities. The completion date would be specified to provide interconnection for testing purposes, in accordance to the commissioning timetable agreed to in Schedule 1. The Company must have right of access to the switchyard to inspect and maintain any of its interconnecting or communication facilities.

14.2 Protective Devices

RAO will specify the electrical protective devices required on the Company's facilities. RAO also will specify how such devices will be set, controlled, operated and when tested for system protection during operation. RAO must have right of access and inspection at all times with reasonable notice.

14.3 Communication Facilities

The Agreement will set forth the operating data required from the Company during operation and in what form that data will be measured, monitored or recorded and by what means it will be communicated to RAO. The requirements for voice, data transmission, on-line instruments and automatic controls will be clearly specified to meet the operating and information needs of RAO's system.

15.0 OPERATION AND DISPATCH

15.1 Operating provisions needed would be for interruption of deliveries in the event of an emergency on RAO's system, force majeure or need to interrupt for repair or maintenance of equipment affecting delivery. RAO will be required to restore delivery as soon as possible, exercising prudence.

15.2 Additional provisions will include a requirement that the Company perform according to best efforts to meet RAO's schedule and for the facilities to respond to any demand whether automatic or otherwise from RAO. It may be necessary to define what constitutes a request from the dispatcher. Provision will also be made for the Company to perform whatever interconnection facilities or generating equipment inspections or tests may be necessary following outages, replacement or repair. Forced outage definition notices and remedial measures associated with forced outages are included. The obligation of the Company with respect to reactive power and voltage control may be specified.

16.0 OPERATING COMMITTEE

An operating committee of the parties shall be established. The Committee would consist of one or more representatives of each party. Its purpose would include but not be limited to:

a) Forum for coordination and general communication between the parties.

b) Establish procedures that may be necessary to implement provisions in the Agreement.

c) Jointly investigate questions and problems that may arise and develop fair and equitable solutions in efforts to avoid disputes.

17.0 MAINTENANCE

17.1 The Agreement shall set forth the month(s) in which planned maintenance is preferred. In addition, the distinction between long-term and short-term maintenance shall be made. Long-term or planned maintenance for each generating unit will be scheduled as agreed upon at the beginning of the year. Short-term maintenance is that which can be scheduled from only a day to less than one month ahead. Short-term maintenance is related to unforeseen equipment problems that must be given attention immediately.

17.2 For planned maintenance the Company will provide RAO with a proposed schedule sixty (60) Calendar Days before the beginning of the year for review and response from RAO.

17.3 The Company will specify the order in which the maintenance of various units of the facility are to be scheduled. RAO will specify the month in which planned maintenance is to be accomplished. Modification of schedules set before the year are changed with mutual agreement.

17.4 The Agreement will provide a total of thirty (30) Calendar Days a year for planned maintenance. Should an unforeseen outage occur, other than that qualified under a force majeure, the Company may utilize the planned maintenance days on as need basis, but with consent of RAO, prior to incurring any penalties.

18.0 METERING

Metering provisions will be included in the Agreement. Meters are provided, installed and maintained by RAO and provisions in the Agreement should address the following:

1. Their exact location.
2. Right of access for all reasonable purposes by the parties.
3. Meters are to be sealed by RAO and the seals broken only for testing, inspection and adjustment and only when both parties have reasonable notice to have representatives present.
4. The frequency of inspecting and testing.
5. The accuracy tolerances to be allowed.
6. Action required and procedures, including billing adjustments, if meters are found to be deficient in accuracy.

19.0 COMPANY'S RECORDS

The Company shall maintain records during the term of the Agreement and for a period of three (3) years after final Tariff payment. However, records which relate to disputes, appeals, arbitration, litigation or the settlement of claims arising out of the performance of the Agreements shall be retained until such disputes, appeals, arbitrating, litigating or claims have been finally settled.

20.0 FORCE MAJEURE

A force majeure provision will be included.

Events that are covered (or not covered) by force majeure excusing performance will be defined. Notices in the event of a force majeure will be specified and the actions required of the non-performing party. Remedies of the affected party to the effects of certain force majeure will be addressed.

Interruption of fuel supply shall be defined in this agreement as a force majeure event. In the event of an interruption of fuel supply to the Project by RAO Gasprom, and upon depletion of backup fuel reserves maintained in accordance with this agreement, RAO shall continue capacity charge payments to the Project Company despite shortfalls in available capacity directly resulting from this event.

21.0 DISPUTE RESOLUTION

21.1 Operating Committee

The committee referred to in Article 16.0 will be given broad duties and power to investigate matters referred to it and resolve whatever problems it can.

21.2 Arbitration

a. Any dispute which may arise between RAO and the Company concerning the interpretation of the Agreement and the performance of the various commitments thereof which cannot be settled amicably shall be submitted to Arbitration, in accordance with international arbitration rules of the [LATER]. The Arbitration place shall be [LATER].

b. The decision of the Arbitration Board which shall be reached by majority of votes with the provision that in the case of parity the decision for which the Chairman has voted shall prevail, must include the motives and arguments of the judgment and shall be binding, final and subject to no appeal, and both parties undertake to fulfill and execute the Arbitration's decision.

c. Any party may submit the decision in question to the Court of Competent jurisdiction in order to render it enforceable under the laws of the country of that Court.

d. Pending final decision of a dispute hereunder, the Company shall proceed diligently with the Project in accordance with RAO's decisions, determinations, instructions and orders.

22.0 GUARANTEES, WARRANTIES, INDEMNITY AND LIABILITY

This provision sets forth the guarantees and warranties that each party makes to the other and the limits of each party as indemnitor to the other.

23.0 INSURANCE

23.1 Unless otherwise expressly provided in the Agreements, the Company shall, at its sole expense, take-out and maintain, in effect, at all times during the performance of the Agreements and until the Company and its contractors of each tier have demobilized and RAO has assumed operation of the Plant, insurance coverage as set forth below. All insurances shall be placed in accordance with the laws of Russia.

23.2 Not less than ten (10) Calendar Days before commencing work at the Site, the Company shall deliver to RAO certificates of insurance identified on their face as to project name and signed by the insurance company or its authorized representative, as evidence that policies providing such coverage and limits of insurance are in full force and effect. Such insurance shall provide that the insurance carrier shall furnish RAO with written notice at least thirty (30) Calendar Days prior to the effective day of any material change, cancellation or non-renewal of the insurance. Such insurance shall name RAO as additional insured and shall provide for an insurer's waiver of subrogation and a cross liability or severability of interest clause in favor of all insured parties contained in the following clauses:

23.2.1 Waiver of Subrogation

The insurers hereby waive subrogation as to any right of recovery which the insured may have against any insured parties including RAO, its parent and affiliated companies and the officers, officials, directors, agents, servants and employees thereof.

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23.2.2 Severability of Interests

The term "The Insured" is used severally and not collectively, and the insurance afforded by this policy is applied separately to each insured against whom claim is made or suit is brought; but the inclusion herein of more than one insured shall not operate to increase the limits of the "Insurer's Liability".

23.3 Additionally, the Company shall be responsible to ensure that its' contractors of each tier carry insurance with the same limits as those stipulated herein against the various risks and exposures arising out of the implementation of the subcontract, with similar naming of additional insured, waiver of subrogation and cross-liability, or severability of interest and other requirements provided for herein.

23.4 Insurances During Plant Construction - From the date of execution of the Agreements until the commissioning of the plant, the Company shall obtain and maintain in force the following insurances as a minimum:

23.4.1 All Risks Course of Construction Insurance, insuring on an "All Risk" basis the project and all Plant to be incorporated therein, with a limit of [LATER] including transit coverage for Plant purchased within Russia and not subject to coverage under 23.4.1 above. The policy should include coverage of the Company's Construction Equipment.

23.4.2 Comprehensive Third Party Liability Insurance, with a limit of [LATER] for any one occurrence, covering legal liability for bodily injury, death and property damage caused by the Works, by the Company's vehicles, tools, equipment or personnel including those of its subcontractors.

23.4.3 Workmen's Compensation Insurance, applicable to industrial illness or injury to cover all employees in accordance with the laws Russia.

23.4.4 Automobile Third Party Liability Insurance, covering all motor vehicles owned, hired or used by the Company.

23.4.5 Business Interruption Insurance is also applicable during construction.

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23.5 Insurance During Power Plant Operation Period - the Company shall, at its own expense, take out and maintain in effect insurance to cover the plant against accidental damage from all normal risks and to a level normal for prudent operation of facilities similar in size and nature to the Plant. In addition, the Company shall secure adequate insurance coverage for all its employees as required by the laws of Russia.

23.6 Business Interruption Insurance - The Company shall furnish necessary insurance against Business Interruption for an appropriate amount consistent with the financial requirements of the Project.

23.7 Insurance Against Political Risks - The Company shall obtain necessary insurance against political risks for the foreign investment component of equity.

24.0 DISCLAIMER

RAO will review certain plans and design and inspect equipment of the Company; however, RAO shall disclaim responsibility for the completeness, quality, feasibility, reliability or performance of the Project Facility subject to review.

The Company, having represented itself as a qualified entity, through engagement of other contractors, having expertise in different areas in which the Company is required to perform under the Agreements, agrees that it has investigated all related aspects of the Project and the payment under the Tariff represents total compensation for all services and conditions of the Project.

25.0 ASSIGNMENT

There will be a prohibition against the assignment or disposition of the Project Facility or responsibility under the Agreement or interest without the express consent of the other party. Appropriate definitions and notice requirements will be provided.

26.0 DISPOSITION OF ASSETS

The parties shall agree to an option of continuation this agreement upon termination of its stated term, or to the disposition of the facility and the Project Company's assets, as well as to the terms of such disposition, prior to execution of the PPA. In case of a planned transfer of assets from the Project Company to RAO, transfer terms should

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include transfer price, acceptable plant condition and inspection of the facility, transfer of personnel, and any training that may be necessary in operation and maintenance of the plant to implement such transfer.

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SCHEDULE 1
Minimum Functional Specification

PROJECT DESCRIPTION

The project relates to the supply, delivery, construction, commissioning and operation of a privately owned, nominal 900 MW combined cycle power generating plant. The plant will be located in the Village of Mostovskoy in Krasnodar Krai, which will generate power for sale to the Russian joint-stock company of power sector and electrification (RAO). The project is designated the Krasnodar GRES Power Project.

TIMETABLE FOR PROJECT COMMISSIONING

The following shall be the staged timetable for commissioning the 2 units of the 900 MW Krasnodar Combined Cycle Plant, with a commercial operation date for full capacity on March 1, 2000.

UNIT	OPERATING MODE	CAPACITY	OPERATION DATE
1	Simple Cycle	300 MW	December 1, 1999
1	Combined Cycle	450 MW	December 1, 2000
2	Simple Cycle	300 MW	July 1, 1999
2	Combined Cycle	450 MW	July 1, 2000

STATION CAPACITY

The gas/oil fired plant shall consist of two modules. Each module shall consist of two combustion turbine generators, two heat recovery steam generators, one steam turbine generator, support facilities and auxiliary equipment. The complete package shall be designed to achieve a total net output, measured on the busbar side of the generator transformers, 50 Hz, of 900 MW at the specified site conditions.

SITE CONDITIONS

The plant shall be designed for the following site conditions:

• Elevation	[LATER]
• Average maximum ambient temperature	[LATER]
• Average minimum ambient temperature	[LATER]
• Design temperature (for process plant equipment)	[LATER]
• Design max. wind speed	[LATER]
• Design river water temperature	[LATER]
• Normal min. & max. sea water level (if applicable)	[LATER]
• Relative humidity	[LATER]
• Seismicity	[LATER]

OPERATION REQUIREMENTS

Each module shall be designed for the following continuous modes of operation.

a) Operation of one combustion turbine and the steam turbine should the other combustion turbine trip out of service or become unavailable for any reason.

b) Operation of two combustion turbines should the steam turbine trip out of service or become unavailable for any reason.

c) Construction of a unit shall not affect units in service and shall enable each unit, upon completion, to synchronize with the RAO grid system without disruption.

The plant shall achieve its base load ratings at an ambient temperature of [LATER]°C and preferably shall be the manufacturers standard equipment and proven by experience. The complete package shall be suitable for automatic control from a central control room, fully protected against all abnormal system conditions and equipment malfunction.

The annual anticipated average operating period at base rating shall be [8000] hours. The design number of starts per year shall be at least [300 for each Unit].

The plant shall be capable of operating in parallel with the existing steam turbine, hydro, and gas turbine units in the system network.

All the equipment in the plant shall be constructed of new material. Design life of equipment shall be [30] years.

FUEL SUPPLIES

The plant shall be capable of burning natural gas and diesel oil fuel when operating for prolonged periods at all load conditions. Natural gas will be the primary fuel and diesel oil will be used as back-up fuel.

Diesel oil storage facilities shall be provided as part of site facilities and shall have sufficient storage capacity to support operation of the plant at maximum load for [8] days.

Natural gas will be provided, via pipeline, by RAO Gasprom. A typical specification of the natural gas delivered to the site is as follows:

Methane, CH_4	[LATER]
Ethane, C_2H_6	[LATER]
Propane, C_3H_8	[LATER]
Butane, C_4H_{10}	[LATER]
Oxygen, O_2	[LATER]
Carbon Dioxide CO_2	[LATER]
Nitrogen, N_2	[LATER]
Low Heating Value	[LATER]
Density	[LATER]

SECURITY

The plant shall be equipped with perimeter fence lighting together with security staffing. Temporary roadways, footways, guards and fences which may be necessary for the accommodation and protection of owners and occupiers of adjacent property, the public, and others shall be provided. Fencing of the site will be provided by the Project Company.

MAINTENANCE SCHEDULING

The planned overhauls are likely to be undertaken during periods of low system power demand. Low system power demands are during the months of [LATER]. However, the

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"take-out" dates will be agreed with RAO in order to account with any system supply constraints due to the scheduling of major plant overhauls elsewhere. Only one unit shall be on planned maintenance at any one time.

ENVIRONMENTAL REQUIREMENTS

The design, construction, and operation of the plant with regard to aqueous discharges, emissions, noise levels, etc. shall be subject to constraints imposed by the national or local laws and regulations of the relevant authorities and in accordance with the World Bank Environmental Guidelines.

The plant shall be provided with silencing equipment so that the sound pressure levels do not exceed 90 dBA and 65 dBA at a distance of 1 meter and 120 meters, respectively, from any equipment.

WATER SUPPLIES

The plant's cooling will be met by use of dry cooling towers or by a combination of dry and wet cooling towers. The Laba River will provide the water supply for plant operations. An intake structure with pumps at the river will provide water as necessary for cooling, water make-up as required by the water treatment facility, and other uses.

The cooling water intake and discharge together with any effluent disposal through the water system will be subject to the governing laws and regulations.

POWER SUPPLY CHARACTERISTICS

Each generator shall be rated (LATER). The generator rating shall be sufficient to accept and deliver the maximum load output of the unit over the ambient temperatures range specified.

Each generator shall be equipped with an outdoor type step-up transformer. Each transformer shall be 250 MVA, suitable for stepping up generator voltage to either 500 kV or 220 kV. Unit transformers connected to the bus bar of their respective generators shall be supplied to service plant auxiliaries.

An online UPS system, [125/250] Vdc batteries, battery chargers and D.C. distribution panels shall be provided. Start-up power shall be from RAO's [500 kV or 220 kV] grid.

CONTROL AND INSTRUMENTATION

The combustion turbines, steam generators, steam turbines and auxiliary equipment shall be capable of operation and control from the control room.

In addition, local facilities shall be provided for the automatic start-up and shut-down. Synchronization shall be automatic with manual override, with local and remote control of output.

The generator and transformer control equipment shall provide complete indicating, regulating, control and protection functions. Remote control panel shall be provided in the control room for remote control indication and metering of the unit.

Control systems which do not affect operation of the generating units on a short term basis such as water treatment, chlorination, oil storage and transfer may be controlled locally to the plant with only grouped alarms and major signals transmitted to the main control room.

The common plant services such as compressed air, station air, fire protection, shall also be controlled from the main control room.

The control equipment shall be implemented by a system proven in the power industry and which has the necessary distribution to ensure that no single equipment failure shall cause trip of a unit.

The level of automation in the logic control area shall allow, as a minimum, that major plant items such as a feed pump, or fuel pump together with all it's auxiliaries may be started by a single initiation and, as such, shall allow automatic starting of a standby unit on failure of the running item.

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The C&I system chosen shall incorporate diagnostic equipment to allow internal faults to be identified and displayed and shall allow rectification.

Transducers for on-line dispatching functions shall be included and be compatible with existing RAO system.

RELIABILITY

Whenever possible, common equipment suppliers, proven and interchangeable components should be used. This will help operability and maintainability of the plant.

A high standard of reliability and availability is required from the plant and the individual plant items. Two aspects of reliability are particularly important:

a) that of meeting target loading and availability values;

b) the requirement that, under normal operating conditions, a single fault on the main or auxiliary plant should not cause the output of more than one generating unit to be lost.

STANDARDS

All plant shall be constructed, installed and tested at the appropriate manufacturer's works, after installation and during plant commissioning in accordance with Russian Federation codes and regulations, or equivalent international codes and regulations.

SAFETY

All ordinates and regulations including, but not limited to, National and Municipal Laws that are in force in the locality of the work regarding safety on site shall be complied with.

SCHEDULE 2
Technical Limits

DESIGN LIMITS

The notice required to start-up the unit and synchronize to the RAO grid system shall vary according to the length of time the unit has been shut down. Table 1 below shows the length of notice required against various periods of shut-down.

Table 1

Length of shutdown	Notice required to synchronize Combustion Turbine/Steam Turbine
8 hours (hot start)	[15 minutes/50 minutes]
48 hours (warm start)	[15 minutes/90 minutes]
72 hours (cold start)	[15 minutes/170 minutes]

The load ramping rate is the steady rate at which the load can be raised. It shall vary depending on the temperature and will be different within varying load ranges. The maximum load ramping rates are shown below in Table 2.

Table 2

Load Range %	Cold Start % per Minute Combustion Turbine/Steam Turbine	Hot Start % per Minute Combustion Turbine/Steam Turbine
0-25	7/0.5	7/1.0
25-50	7/1.0	7/2.0
50-100	7/1.0	7/3.0

The minimum safe loading shall be [10%] of the capacity for each generator unit.

The generator shall be capable of operating at full capacity with a power factor of 0.80lagging or [0.9] leading.

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At no load, the generator has a reactive capability of [LATER] MVAR either lagging or leading.

The unit shall be designed for a limited number of starts over its design life of [30] years. The numbers are summarized in Table 3 below.

Table 3

Type of Start	Total Maximum of Starts Combustion Turbine/Steam Turbine	Maximum Number of Starts per Year Combustion Turbine/Steam Turbine
Hot (8 hr. shutdown)	[LATER]	[LATER]
Warm (32 hr. shutdown	[LATER]	[LATER]
Cold (150 hr. shutdown)	[LATER]	[LATER]

The voltage on the high voltage system shall not vary beyond [±5%].

The Company shall advise RAO of any additional operating constraints and limits which may from time to time apply to the unit.

FAULT LEVELS

Maximum

For the purpose of design, it may be assumed that the [500] kV fault levels will not exceed [LATER] kA (symmetrical rms) for the foreseeable future after taking into account contributions from the plant and the RAO system.

The [LATER] kV switchgear on the RAO system is currently rated between [LATER and LATER] kA. The contribution to external [LATER] kV faults from the plant should be within the ban [LATER] kA to [LATER] kA (symmetrical rms) based on sub-transient reactances and on unit MVA ratings. Sufficient data to enable [LATER] kV fault contributions to be assessed by RAO shall be submitted.

Minimum

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For the purpose of design, stability and protection checks, the following characteristics of the RAO system and the plant are to be assumed. All values are given for information and are subject to confirmation and more detailed study. Sufficient information shall be provided to RAO to verify preliminary assumptions on the characteristics of the plant. All fault levels quoted are in symmetrical rms currents at [ ] kV, and are sustained values, i.e. the minimum delivered over a period from zero to 10 seconds after fault inception after taking AVR action and field forcing into account.

a) Minimum [LATER] kV fault level (all contributions included) - [LATER] kA.
b) Minimum RAO contribution (all sets at the plant and minimum RAO interconnection) - [LATER] kA.

SCHEDULE 3
Interconnection Facilities

DESCRIPTION OF FACILITY

A [LATER] kV switchyard facility with required interconnection to the grid shall be provided on behalf of RAO. [RAO shall compensate the Company after construction is completed and will own and operate the switchyard facility].

The connection between the plant and the RAO grid system shall be made via [500 kV double circuit] transmission line and shall terminate at the [LATER].

The operating range of voltage will be [LATER] kV ±5%.

DESIGN DATA

	Combustion Turbine	Steam Turbine
1. Generator	(Data will be Supplied Later)	

- MVA Capacity, MVA
- Rated Voltage, kV (rms)
- Power Factor
- Maximum Active Power Capacity, MW
- Minimum Active Power Capacity, MW
- Reactive Capability Curves at Maximum and Minimum Operating Voltage
- Stator Winding Connection
- Unsaturated Direct Axis Synchronous Reactance, % on rated kV, MVA
- Quadrature Axis Synchronous Reactance
- Negative Sequence Reactance
- Zero Sequence Reactance
- Leakage Reactance

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	Combustion Turbine	Steam Turbine
• Potier Reactance		
• Direct Axis Open Circuit Time Constant		
• Direct Axis Open Circuit Subtransient Time Constant		
• Quadrature Axis Open Circuit Substransient Time Constant		
• Direct Axis Short Circuit Transient Time Constant		
• Direct Axis Short Circuit Subtransient Time Constant		
• Inertia Contant (generator plus prime mover), MW, Sec/MVA		
2. Exitation System		
• Type		
• Exciter Rated Load Field Voltage, V		
• Nominal Exciter Ceiling Voltage (+ polarity), V		
• Nominal Exciter Ceiling Voltage (- polarity), V		
• Overspeed Curve Following Full Load Dropping		
Provide Block Diagram of Excitation Systems, Specify the Values of Gains, Time Contants and Ceiling (+/-), Specify the Adopted PO System		
3. Generator Transformer		
• Rating, MVA	250	250
• Rated Voltage, kV		

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	Combustion Turbine	**Steam Turbine**
• Maximum and Minimum Operating Voltages, kV (rms)		
• Connection of Winding		
• Positive and Zero Sequence Reactances % on Rated kV and MVA Base		
i. HE-L (Leakage)		
ii. HE-T (Leakage)		
iii. L-T (Leakage		
• X Air Core (from L.V. Terminal)		
• Saturation Curve at no Load V (rms) versus I (rms)		

4. Suspension Insulators (if applicable)

- Type
- Color
- Disc
- Russian GOST Standard
- M&F Strength
- Impact Strength
- Spacing
- Leakage Length
- Voltage Rating
- No. of Elements, Tension String
- No. of Elements, Suspension String

5. Switch & Bus Insulators (if applicable)

- Type
- Station Post
- Sky Greg Porcelain
- Russian GOST Standard

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	Combustion Turbine	Steam Turbine
• Nominal Voltage		
• BIL Voltage		
• Leakage Strength		
• Cantilever Strength		
• No. of Units in stack		
6. Manual Group Operated Disconnect Switches (if applicable)		
• Type		
• Quantity		
• Rated Voltage		
• Rated Max. Voltage		
• Rated Frequency		
• Rated Continuous Current		
• Rated Short-time Current		
i. Momentary		
ii. Three Seconds		
• Operating Handle Above Grade		
7. Motorized Group Operated Disconnect Switches (if applicable)		
• Type		
• Quantity		
• Russian GOST Standard		
• Rated Voltage		
• Rated Max Voltage		
• Rated Frequency		
• Rated Continuous Current		
• Rated Short-time Current		
i. Momentary		
ii. Four Seconds		

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	Combustion Turbine	Steam Turbine
• BIL		

8. Conductors
   - Type
   - Conductivity

GROUNDING & LIGHTING

A complete and effective lighting and grounding facilities shall be provided.

1. Lighting Fixtures

   The outdoor substation luminaries shall be structure mounted lamps. The fixtures shall have such characteristics that the light must be displayed vertically upwards as well as horizontally and a small quantity downwards, by the special reflector.

2. Induction Type Potential Transformers

   The induction type potential transformers shall be the oil immersed, outdoor type, single high voltage and graded insulation for [LATER] kV system. The transformers shall have the following design data:

   System Rated Voltage kV r.m.s.
   Primary Voltage Rating kV r.m.s.
   Primary Connection
   No. of Secondary Windings
   Voltage Ratio
   Accuracy Class/Standard Burden

3. Lightning Arrestors

   The lightning arrestors shall be station class, intermediate, single pole, outdoor type and shall be installed on separate steel supports. Arrestors shall have the following rating and design conditions.

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Nominal System Voltage	
Rated Max. Operating Voltage	
BIL of Equipment	
BIL of Transformers	
Frequency	50 Hz
Design Fault Level	
System Grounding	
Grounding Transfo.	
Arrester Rating	
Max. 100% Impulse Sparkover (1.2 x 20 us)	
Max. Discharge Voltage with Impulse Current	
Min. 50 cps sparkover voltage	

4. <u>Circuit Breakers</u>

The circuit breakers shall be Type (Later), outdoor enclosure, single-throw and furnished with electro-pneumatic (or equivalent) mechanism. The breaker shall be electrically and mechanically trip-free. The breakers and its auxiliaries shall have the following data:

A. Quantity Required	3/Unit
B. System Characteristic	
1. Line to line voltage	
2. Number of phases	3
3. Frequency	50 Hz
4. System of grounding and method of grounding	
C. Application	
1. Type of circuit	
2. Environmental Conditions	
3. Altitude	
4. Ambient temperature range	
D. Circuit Breaker	
(i) Electrical Characteristics	
1. Rated voltage rms.	
2. Symmetrical interrupting	

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3. 50 Hz. rated continuous current, rms.
4. Short-time current carrying capability three seconds, symmetrical current, rms.
5. Rated interrupting time 50 Hz. basis
6. Insulation levels, (BIL)
7. Control voltage

(ii) Physical Characteristics
1. Location and type
2. No. of poles
3. Tank
4. Type of mounting
5. Centre line phase spacing

(iii) Bushing Characteristics
1. Voltage rating
2. Impulse test
3. Leakage length
4. Terminal connectors

F. Current Transformers
1. Russian GOST Standard, multi-ratio
2. No. of current transformers each bushing
3. No. of current transformers per breaker
4. Accuracy class

G. Final Paint Finish

H. Auxiliary Supply

I. Auxiliary Switches

SCHEDULE 4
Commissioning and Testing

GENERAL

Commissioning and acceptance tests shall be performed during start-up operations to ensure that all items of the plant can perform in a satisfactory manner and that all the intended functions of such equipment are proved. Only after successful completion of these tests will the units be accepted. The Project Company shall satisfy RAO that the plant can be relied on to generate both electric and thermal power.

During all commissioning and acceptance testing, the Project Company's start-up personnel shall be present and shall be responsible for the operation of the units. RAO will provide operating personnel to work under the direction of the Project Company's start-up personnel during the commissioning and acceptance tests.

The Project Company and RAO shall agree on safety procedures for the commissioning and acceptance tests. These procedures will cover permits to work, rules for operation of the "Tie in Points" on RAO's system, compliance with RAO's safety rules, and all other aspects of safety pertaining to the operation of equipment and plant.

The Project Company shall notify RAO in writing when tests are to be performed.
[Twenty-four (24)] hours notice should be given for tests to be performed on site.

COMMISSIONING AND ACCEPTANCE TESTS

1. Test and Start-Up of Auxiliaries

    All auxiliaries shall be tested to verify that they can be operated safely and that their performance is up to the design specifications and that all protective devices, mechanical as well as electrical, are functioning effectively and at their correct settings. Interlocks which prevent start-up under dangerous conditions, the operation of pressure relief devices, over temperature devices, and over current devices are especially important. Automatic start-up of stand-by auxiliaries on loss of running auxiliaries are also required to be tested.

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2. Control System

Automatic control systems shall be tested for correct functioning although it is appreciated that the final trimming of the controls needs to be done at a later stage.

3. Synchronizing Checks

Before the machines are permitted to be run in parallel with other machines, RAO will specify what tests shall be done in order to ensure that it is safe to do so.

These tests shall be witnessed by RAO and shall be satisfied that all the instruments associated with the synchronizing operation are functioning correctly.

4. Electrical Protective Devices

All electrical protective systems, circuits, devices and instruments shall be tested on site to prove both operation and stability as well as the compliance of the actual relays and current transformers with the manufacturer's published information. RAO shall be entitled to receive from the Project Company full documentation of these tests before accepting any system as operational.

5. Mechanical Protective Devices

Tests on over-speed trip and other mechanical protective devices shall be carried out to prove the effectiveness of their operation.

6. Stability

The automatic voltage regulator of the alternator shall be checked for proper and stable operation.

7. Noise Level

Test shall be carried out to check that the units do not exceed the limits of noise levels laid down by the manufacturer's specifications.

TESTS ON COMPLETION-GUARANTEE TESTS

1. General

The Project Company shall prove by tests to RAO that the guaranteed figures for the electric and thermal outputs and net heat rate which were quoted by the Project Company are realized. Guarantee tests shall be carried out on each unit.

Base load shall mean the output developed by the individual unit on a continuous basis assuming [8,000 hours/year] operation under site conditions.

2. Net Heat Rate Tests

The net heat rate of the plant shall be defined as the heat content in Kcal of the fuel consumed for each kWh of electrical energy into the main plant busbars.

All electrical auxiliaries shall be supplied by each generator during the tests.

The net heat rate shall be determined by the "Fuel Input/Net Energy Output" method, under steady state conditions. Should the conditions at the time of the tests vary from the Guarantee Conditions then corrections shall be applied in a manner agreed upon between RAO and the Project Company in order to compare the average of the corrected results with the guaranteed figure.

The net heat rate test shall be performed as soon as possible.

The tests shall be performed using [natural gas]. The Project Company shall supply calibrated flow meters whose calibration records are to be made available to RAO for approval prior to the test.

The Project Company shall submit for approval by RAO details of the test procedures and apparatus to be used to determine density, calorific value, and temperature of the fuel used during the test.

The test load points are to determine plant performance at part load so that the most efficient method of operation can be determined. All results to be corrected to site design conditions.

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The net electrical power output shall be measured on the busbar side of the generator transformers. The Project Company shall provide specially calibrated current transformers and Watt hour meters to give a metering accuracy within [+ 0.2%] and these shall be a permanent part of the installation.

The Project Company shall supply all measuring devices and equipment for determining the cooling water flow rate through the condenser. During the design of the plant, the Project Company shall submit for the approval of RAO a drawing illustrating the installation details and position of the measuring devices for the main flow and any devices for subsidiary CW flows.

The Project Company shall also supply details of the standardization or calibration procedures for these devices.

The Project Company shall supply all equipment necessary for the conduct of the net heat rate test, including all equipment necessary for the determination of the performance of the individual plant components.

3. Generator Heat Run Tests

The generator shall be tested to ensure that the temperature increases in the generator stators and rotors do not exceed the limits laid down in the manufacturer's specifications. These tests shall be carried our with the generators at full load and at rated power factor.

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SCHEDULE 5
Metering Standards and Testing

PROVISION OF TARIFF METERING

The metering points to record the MWH and MVARH exchange between the plant and the RAO system shall be as shown in [Figure]. The current and voltage transformers will measure current and voltage on the outgoing circuits of the plant [substation]. The meters, owned by RAO, will be located within the [sub-station in a building housing all marshalling cubicles, control and metering panels and communication equipment]. Photographic facilities will be provided by RAO as part of the verification process for routine meter readings.

The meters and transformers provided by RAO shall be to a mutually agreed international standard providing a measured accuracy of [+0.5%].

TESTING

The calibration of meters will be checked to ensure that the accuracy remains within the specified limits.

The method of calibration and the frequency of tests will be agreed between the Company and RAO based on knowledge of the performance and the design of the installed meters and the manufacturers recommendations.

Compensation will be made for the errors of current and voltage transformers in the meter calibration or during the computation of records. Current and voltage transformers will be tested for ratio and phase angle errors following manufacture at an accredited testing station in the presence of representatives from the Company and RAO. Test certificates issued by the testing station will be issued independently to both parties.

Testing and calibration shall be carried out by RAO after giving appropriate notice to the Company in line with the agreed frequency of testing or in the event of either party having reasonable cause to believe the meters are outside specified limits. During such tests and calibration, the Company shall have the right to have a representative present at all times.

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SCHEDULE 6
Indexation and Adjustment

GENERAL

[The Project Company shall provide in this section basic charges that make up the tariff.

a) Performance Charge

To cover the fixed costs of operating and managing the plant including debt service and a return on equity.

b) Flow-Through Charge

To cover costs that are subject of a direct flow through to RAO including taxation and insurance.

c) Energy Charge

To cover the incremental fuel costs and variable operating and maintenance costs.

d) Unit Start-Up Charge

To cover the cost of unit start-ups requested by RAO.

e) Unit Commitment Charge

To cover the "no-load" fuel, operating, and maintenance costs related to hours of operation once a unit is started and synchronized to the national grid.

f) Hot Standby Charge

To provide further flexibility to RAO, which may wish to hold units in hot standby mode whereby they would be ready to respond quickly to RAO's.]

INDEXATION AND ADJUSTMENT

[The Project Company shall provide in this section the tariff adjustments, including formulas. The indexation provisions shall reflect the changes in costs faced by the Project Company that are outside its reasonable control, including the price of fuel, exchange rate movements, and inflation affecting costs. The indexation provisions shall also use readily available and generally acceptable data.]

TARIFF RE-OPENER

[The section shall include events which will entitle the Project Company for tariff re-opener. These events which would not reasonably have been anticipated and are beyond the control of the Project Company can include force majeure, change in legislation, and delays in commissioning by RAO.]

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SCHEDULE 7
Operating Committee

APPOINTMENT OF COMMITTEE

1. As from the date of this Agreement, the parties shall each appoint [three] representatives who shall, acting jointly, be responsible for the coordination of the construction and operation of the interconnection facilities, transmission facilities and the RAO grid system with the construction and operation of the plant. Without limiting the generality of the foregoing, the power and duties of such representatives ("the Committee") shall include:

   a) the coordination of the respective programs of the parties for the construction and commissioning of the RAO facilities and the plant, and agreement where necessary upon the respective commissioning procedures.

   b) the discussion of the steps to be taken on the occurrence of any event of force majeure, or the shutdown or reduction in capacity for any other reason of the interconnection facilities transmission facilities or the plant.

   c) the coordination of scheduled maintenance programs.

   d) the coordination of annual, monthly, weekly and daily forecasts or requirements from the plant.

   e) consideration of any notification by the parties of proposed or anticipated changes in the levels of supply of or demand of fuel for the plant.

   f) coordination of the operation of the fuel supply facilities supplying fuel to the plant.

   g) consultation on the insurance program to be undertaken by the Company for the purposes of this agreement.

   h) development of operating procedures.

i) safety matters affecting both the parties or their contractors.

2. The Committee may agree on procedures between them for the holding of meetings, the minuting of meetings and the appointment of committees and sub-committees.

3. In case of difficulty, the Committee or any member may refer the matter referred to in Paragraph (1) to the Chief Executives of and the Company for further consideration. In the event that the Chief Executives are unable to reach agreement within [7] days or such longer period as they may agree then either party may refer the matter for an expert [Arbitrator].

SCHEDULE 8
Operating Procedures

SCHEDULING AND DISPATCH

In order to assist with scheduling of the plant to meet the requirements of RAO, it is agreed that the following procedures will be adhered to:

1. Month Ahead Notification - Not less than [14] days before each month RAO shall provide to the Company estimated requirements on a day by day basis, for net electrical output and unit commitments during that month and also provisionally for the following month, but shall not be bound by these figures.

2. Week Ahead Notification - Not less than [48] hours before each week RAO shall provide to the Company estimated requirements, on an hour by hour basis, for net electrical output, unit commitment, unit start up and unit hot standby during that week and also, provisionally, during the following week but shall not be bound by these figures.

3. Plant Availability Notification - To enable RAO to give final schedules of requirements [as in Item 4 following] the Company shall, by [1200] hours each day, inform RAO of the declared net capacity (being dependable capacity less any reductions due to scheduled outages, existing forced outages and temporary de-ratings) available during each hour of the day commencing [36] hours ahead and provisionally, for the following day.

4. Day Ahead Notification - Not less than [24] hours before each day RAO shall provide to the Company firm requirements, on an hour by hour basis for net electrical output, unit commitment, unit start up, unit hot standby, spinning reserve and reactive power during that day and also, provisionally, during the following day. The firm requirements shall not be binding upon RAO and the Company shall not unreasonably withhold its consent to any reasonable request from RAO for an alteration to its requirements.

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SCHEDULE 9
Construction Reports

During the duration of the Construction Contract, the Project Company shall submit to RAO the Monthly Progress Report. Such report shall include the following:

- A narrative summary of the Contract history to date, including description of progress achieved, list of significant milestone events accomplished and related dates.

- Narrative description of major near-term events scheduled and their impact on the Contract.

- A report of the monthly installation of quantities measured against the total estimated for the major items. The items are to be reported in the following format:

Item	Est. Qty.	Qty. This Mo.	Qty. Accrued	Percent Complete	Notes

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SCHEDULE 10
Letter of Credit

[Bank's Name and Address]

We hereby issue in the [Project Company] favor this irrevocable Letter of Credit.

Account:	[Puchaser's Name]
Amount:	[$ amount equals to two months average projected capacity purchase price payments and energy purchase price payments]
Expiry:	[Date]
Covering:	Two months average projected capacity purchase price payment and energy purchase price payments

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APPENDIX E

PRINCIPLES OF THE IMPLEMENTATION AGREEMENT

PRINCIPLES OF THE IMPLEMENTATION AGREEMENT*

By and Between

KubanGRES Co.

and

The Government of the Russian Federation

* Principles recommended by Consultants, currently undergoing review by all parties 12/04/95

IMPLEMENTATION AGREEMENT OUTLINE

1.0 Introductory Statements

This agreement is executed between KubanGRES Co. Ltd. (Project Company) and the Government of the Russian Federation (Government). The agreement is to identify the reciprocal obligations of the Government and the Project Company as required to build, own and operate the Krasnodar Power Project at the Mostovskoy site.

This agreement has two main objectives. The first is to ensure the development of a facility for the World Bank loan designated for the Project Company, which will constitute an agreement between the Government and the World Bank, and the availability of the facility to the Project Company. The second objective is to provide assurances to the Project Company that the Government would not adversely impact the creditworthiness of the Project Company and its Power Purchase Agreement (PPA) in its process of restructuring the power sector.

The term of the agreement is the longer of:

1 30 years starting from the earlier of the Commercial Operations Date,

2 Any extension by reason of an event of force majeure under the Power Purchase Agreement (PPA) or the Fuel Supply Agreement (FSA).

2.0 Obligations of the Project Company

The rights and obligations of the Project Company will include, but not limited to the following:

- Negotiate and execute all agreements needed to implement the project,
- Procure all necessary financing, in the form of debt and equity on a limited recourse basis,
- Service all outstanding loans, including the World Bank loan, that have been obtained at financial close of the project,
- Provide payments of $______ per year to the Government in return for the latter's sovereign guarantees of the World Bank loan,

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- Cover all transaction fees payable by the Government or by the Project Company to the World Bank and other lenders,
- Obtain all licenses and permits necessary to implement the Project,
- Establish and maintain a structured Project Company organization in the Russian Federation in accordance with laws and regulations of the Russian Federation.

3.0 Obligations of the Government

The rights and obligations of the Government will include, but not limited to the following:

- Ensure the Project Company's right to design, construct, own and operate the plant within the laws of the Russian Federation,
- Support the Project by undertaking generally to promote and support all applications for the specified consents required to implement the Project and to use its good offices in relation to the construction of the Plant.
- Ensure the convertability of foreign exchange and the Project Company's and its shareholders' ability to repatriate earnings, and permit the free transfer of all funds connected with the Project Agreements,
- Extend to the Project Company any benefits and incentives available under the Russian Federation laws including exemption from taxes and custom duties,
- Negotiate and execute a loan agreement with the World Bank to establish the World Bank loan facility for the project, allowing utilization of the facility by the project, without delay and without change in terms other than those identified in this agreement,
- Use its good offices with the Federal Energy Commission to provide regulatory approval of the Power Purchase Agreement (PPA) executed between the Project Company and RAO EES Rossii, and timely regulation and enforcement of terms identified in the PPA. Ensure proper compensation for unnecessary losses to the project caused by regulatory delays caused by the Government,

- Provide physical security to the Krasnodar plant upon request of the Project Company.

4.0 Government Approvals and Guarantees

In the event of a change in law in the Russian Federation that affects the viability of the Project Company, the Government undertakes to fulfill all debt obligations that have been obtained by the Project Company at the time of financial close. The Government will also compensate equity shareholders of the Company in the amount of the original equity investment, plus the equivalent of three years of expected returns on equity.

In the event of Government action that affects the creditworthiness of RAO EES Rossii as the principal purchaser of power from the project, either through divestiture, restructuring, or regulatory intervention, the Government will give due consideration to the interests of the Project Company, and its debt and equity investors. Upon such Government action, the Project Company may request, and the Government will be responsible for identifying a creditworthy entity for assignment of purchaser responsibilities under the PPA. The Project Company as well as its lenders will be entitled to verify the creditworthiness of the new proposed purchaser and approve assignment of the PPA.

In the event of such an assignment of the PPA, it is agreed between the parties that no changes may be made in terms of the agreement without written approval of the Project Company and its lenders. The government shall provide backstop guarantees to the lenders and equity investors of the Project Company to cover a default by the purchaser upon reassignment of the PPA.

5.0 Termination

If an event of default occurs, the affected party may exercise its rights identified under this agreement. The parties will mutually define what constitutes a Government or a Project Company default. The parties will also define a methodology for valuing debt and equity investments covered by the Government guarantee at any point in time of the project's operation.

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APPENDIX F

PRINCIPLES OF THE HEAT PURCHASE AGREEMENT

PRINCIPLES OF THE HEAT PURCHASE AGREEMENT*

By and Between

KubanGRES Co.

and

Mostovskoy Region Administration

* Principles recommended by Consultants, currently undergoing review by all parties 12/04/95

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HEAT PURCHASE AGREEMENT OUTLINE

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HEAT PURCHASE AGREEMENT OUTLINE

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1.0 INTRODUCTORY STATEMENTS

This first article of the Heat Purchase Agreement (Agreement) identifies the Mostovskoy Region Administration of Krasnodar Krai (Administration) and the Project Company Kuban GRES (the Company) as the contracting parties and shall state that, under this Agreement, the heat energy generated by the Plant shall be sold to the Administration by the Company. This section may state in the form of "whereas" clauses all the steps the parties have accomplished or intend to take upon signing the Agreement.

2.0 DEFINITIONS

2.1 Defined terms shall be provided for convenience and to be precise without repetition in the contract wording. Defined terms are limited only by the desires of the contracting parties.

2.2 The following words and expressions shall have the following meanings:

- "Administration" - means the local governmental administration of the region of Mostovskoy, which also includes the Village of Mostovskoy, in the Krasnodar Krai (region) of Russia.
- "Agreement(s)" - means the contracts and documents between the Project Company and the Administration or third parties.
- "Approved" or "Approval" - means approved by or approval of the Administration unless otherwise stated. All approvals shall be in writing.
- "Calendar Day" or "Days" - means consecutive days, including weekends and Holidays.
- "Capacity Charges" - means a specific component of Tariff which the Project Company is entitled to receive upon the start of Commercial Operation.
- "Commercial Operation" - shall mean that the Completion Certificate for the Project has been issued and the Project Company is entitled to receive payment for the Capacity Charges defined under the Agreement.

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- "Completion Certificate" - means the certificate to be issued and signed by RAO EES Rossii and delivered to the Project Company, as stipulated in the PPA, signifying satisfactory completion of the construction phase of the Project, completion of performance testing, and the beginning of plant operations. Upon issuance of the completion certificate, the Project is deemed ready for commercial operations and the Project Company is entitled to receive payment for the capacity charges defined under the Agreement.

- "Construction Equipment" - means all appliances or things of whatsoever nature required in or about the execution, completion, maintenance or operation of the works, but does not include permanent plant or other items intended to form or forming part of the works.

- "Contractor(s)" - means any person, firm or firms, company or companies under contract to the Project Company to perform work on or supply goods for the Project.

- "Drawing" - means collectively, all the drawings listed in the Agreements and also such supplementary drawings as the Project Company will issue from time to time. The word drawings shall also be understood to include documents such as procedures and manuals.

- "Energy Charge" - means the price paid by the Administration to the Project Company for Net Energy Output as adjusted from time to time in accordance with this Agreement.

- "Financial Close" - means the execution of the financial agreements between the Project Company and its lenders. Specifying the terms and conditions and the durations of the financing. Financial Close shall also mean that certain conditions precedent to the availability of funds has been fulfilled and the Project Company has received commitments for the required equity.

- "Force Majeure" - means an event or occurrence specified in this Agreement.

- "Forced Outage" - An interruption of a unit's generating capability that is not the result of (i) a request by the Administration in accordance with this Agreement; (ii) a Scheduled Outage; or (iii) an event or occurrence of Force Majeure.

- "Guaranteed Net Output" - means the total output of the Plant less the agreed upon auxiliary heat consumption at the Plant.

- "Interconnection Facilities" - All the facilities located outside of the Plant Site to be constructed by or for the Administration to enable it to receive and deliver capacity and energy in accordance with this Agreement plus the Metering System.

- "Operating Committee" - means the committee established between RAO and the Project Company for the purpose of determining operating standards and procedures for the Plant.

- "Plant" - means the generating plant including all auxiliaries and support facilities including the switchyard located in the Village of Mostovskoy in Russia.

- "PPA" or "Power Purchase Agreement"- means the agreement between KubanGRES and RAO EES Rossii for the sale and purchase of electricity output from the plant to the RAO grid or wholesale market.

- "Project Company" - means the Russian Joint Stock Company Kuban GRES established by a group to undertake the Project activities in accordance with the Agreements.

- "RAO EES Rossii" - means the Russian Joint Stock Company for elecrification, which is designated as the power purchaser in the Power Purchase Agreement with the Company.

- "RAO Gasprom" - means the Russian Joint Stock Company Gasprom which owns and operates Russia's natural gas transmission and distribution networks, and in this context includes Kuban Gasprom.

- "Scheduled Outage" - means a planned interruption of a unit's or the

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Plant's generating capability that (i) is not a maintenance outage; (ii) has been scheduled and allowed by the Administration; and (iii) is for inspection, testing, preventive maintenance, corrective maintenance or improvement.

- "Site or Jobsite" - means the land and other places provided by the Krasnodar Krai and Mostovskoy Administrations on, under, or through which the Project is constructed and the work is executed or carried out, and any other lands or places provided by the Administration for the purpose of the Agreements, together with such other places as maybe specifically designated in the Agreements as forming part of the Site or Jobsite.

- "Tariff" means the agreed upon payments by the Administration to the Project Company under the Heat Purchase Agreement.

2.3 Singular and Plural

Words importing the singular only also include the plural and vice versa where the context requires.

3.0 TERM OF AGREEMENT

3.1 The term of this Agreement begins at the effective date of the Agreement and ends upon termination of the PPA. The provisions applicable to the operation of the Plant shall become effective when the construction of the Plant has been completed and the Completion Certificate has been issued. The construction period shall be in accordance to Schedule 1 of the Power Purchase Agreement (PPA).

3.2 In the event the construction period exceeds the schedule identified in Schedule 1 of the PPA, the Administration may consider an extension of the period for the Agreement, such that the Agreement will maintain its intended effective life from the date the Completion Certificate was issued. The Administration agrees to coordinate such extension with RAO to ensure that terms of commissioning of the plant coincide with the revised PPA. Extension of the Agreement period will not relieve the Company of any penalties for delay or other action that the Administration may be entitled to, per the Agreement.

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3.3 A non-binding option will be included for extension of the Agreement. The procedures and their timing shall be set forth in order that any agreed upon extension will be determined two (2) years before the expiration of the Agreement.

4.0 PROJECT FACILITIES

4.1 The Company is obligated under the Heat Purchase Agreement (HPA) to design and construct the Plant and Interconnection Facilities to meet the specifications in Schedule 1 of the PPA.

4.2 The Company shall use the metric system of measurement for all designs, plans and drawings.

4.3 The design and construction of the Project Facilities shall be in accordance with the internationally recognized codes and standards and shall be referenced in the Agreement. Subsequent changes to these codes and standards shall be agreed between the parties.

5.0 TESTING

5.1 The Agreement will describe the detailed procedures for testing of the Project Facilities based upon international codes and standards and the specifications of the Project. The Agreement will require the following Performance Tests to be successfully carried out prior to issuance of the Completion Certificate, Initial Performance Test:

- Net plant output of ___ GCal/h at full capacity adjusted for ambient site conditions and fuel characteristics, based on a staged approach as indicated in Schedule 1 of the PPA.

- Net plant heat rate at Net plant output as guaranteed by the Company.

- Reliability of the plant demonstrated by a continuous operation of not less than five (5) Calendar Days. Appropriate adjustments such as for protective relays etc. shall be deemed to have been completed prior to the reliability run.

- Interconnection Facilities testing.

5.2 The Agreement shall state the time limits, as necessary, for exchange of information, developing rules and procedures, commenting and agreement of the parties. Adequate notice provisions for dates of tests and opportunities for appropriate personnel to be present and to receive and review test data should be provided.

5.3 Provisions also should be made for timely resolution of any test disputes in order that remedies be effected for any deficient facilities and that conforming facilities be approved for operation as expeditiously as possible.

6.0 COMPLETION AND INITIAL OPERATION

6.1 Operations will commence when all tests are satisfactorily completed and RAO EES Rossii, under the Power Purchase Agreement, issues a Completion Certificate. The date of commencement shall be the date when the operative provisions of the Agreement become effective. It also determines the termination date of the Agreement.

6.2 The required date for completion, testing and commercial heat production of the plant shall be in accordance to a timetable to be developed by the Parties at a later time, depending on the heating needs of the Adminsitration

7.0 PENALTIES FOR FAILURE TO MEET GUARANTEED OUTPUT DURING INITIAL PERFORMANCE TEST

7.1 The Parties acknowledge that failure of the Company to deliver at the time of the initial performance tests, the agreed upon Guaranteed Net Output at one hundred percent (100%) load will be cause for a one time penalty. The Parties agree that the Company shall pay to the Administration as a penalty, a sum of (LATER) per GCal/h shortfall based on the difference between the Guaranteed Net Output and the actual net output. In addition, if the Company fails to meet a ninety-five percent (95%) of Guaranteed Net Output for the plant, the Administration reserves the right to reduce the capacity charge payable to the Company by a proportionate amount.

The net output established during the initial performance testing, if different from the Guaranteed Net Output, will become the new unit rating and will become the basis for performance measurements during the Plant operations.

The appropriate adjustments for ambient conditions versus the agreed upon operating conditions and due to heating values of the fuel shall be made to arrive at the actual heat output.

7.2 Notwithstanding the provisions stated above, if the plant fails to achieve 90% of the Guaranteed Net Output at the repeat performance test, the Company shall be required to make good the deficiency in the net output capacity of the whole Plant up to the amount of ___GCal/h. Such making good shall not entitle the Company to any increase in the tariff which would have ruled had the above provisions been met.

The Company shall submit its plan for such making good to the Administration within 45 days from the repeat performance test. In the event the plan is not submitted to the Administration by the forty-fifth day, the Administration reserves the right to defer any payments due to the Company under the Fixed Capacity Charge for the Plant component of the tariff until receipt of the plan.

8.0 ENERGY DELIVERY AND SCHEDULING

8.1 Delivery

8.1.1 The point of delivery of the electrical energy purchase and sale will be at the meter installed at location of interconnection. The Company retains title to and accepts all responsibility for heat on the generating side of the point of delivery and the Administration on the other side of the point of delivery.

8.1.2 The Company shall have no claim, other than continuation of capacity charge payments, if the Administration can not receive energy in accordance with the mutually agreed energy delivery schedules due to an outage of the heating system, from the time at which the Administration informs the Company of such outage.

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8.1.3 The Company shall supply to the Administration with up to [Later] GCal per year of heat energy, at a pressure of __ Bars, flow rate of __ t/hr, and temperature of __ C°,

8.1.4 The Administration shall purchase from the Project up to [Later] GCal per year of heat energy, with maximum peak capacity of __ GCal, with a return pressure of __ Bars, temperature of__ C°, and with losses not to exceed __%,

8.2 Scheduling

Preliminary scheduling of heat delivery shall be on an annual basis for planning and budgeting purposes by both parties. The proposed schedule will be initiated by the Administration for review by the Company sixty (60) Calendar Days before the year begins for timely exchange of information and comments. The schedule may be based upon historical record of the load demand for the previous year, with appropriate adjustment factor for the increase in demand for the coming year. Similarly the planned maintenance scheduling shall be in parallel with the preliminary delivery schedule, with the Company specifying the amount of time needed for planned maintenance for each generating set and the preferred sequencing. The Administration shall have the right to coordinate with RAO to jointly specify the months during the year when the planned maintenance may be scheduled.

The Company will exercise best efforts to supply the hourly schedule energy delivery and spinning reserve. However, in the event of a forced outage or partial outage the Company promptly notifies the Administration and is relieved of the delivery obligation to the extent of the magnitude and duration of the outage.

9.0 FUEL

9.1 Fuel Supply

The natural gas for Plant startup, commissioning and operation will be supplied at the Site by RAO Gasprom, pursuant to the Fuel Supply Agreement, with full reimbursement of fuel costs for heat generation by the Administration for the term of this Agreement.

9.2 Backup Fuel

The Company shall provide for storage facilities for liquid fuel at the site. All quantities of liquid fuel shall be provided and paid for by the Company at prevailing market prices. On the Commercial Operation Date, the Company shall have available at Jobsite, full quantity of liquid fuel in the tanks, at its cost. Should the supply of fuel gas be interrupted, the Company shall operate the Plant with liquid fuel except the Company shall have no obligation to use the liquid fuel for more than eight [8] Days in the event that the liquid fuel is not delivered to the Plant. The Energy Charge to be paid by the Administration to the Company under such conditions shall be adjusted. If the Company utilizes liquid fuel during such an interruption for the operation of the Plant, it shall as soon as practicable ensure that the levels of liquid fuel are replenished and maintained. The supply of liquid fuel for testing purposes shall be the responsibility of, and at the cost of, the Company.

10.0 PRICE FOR ENERGY

10.1 Tariff

All transaction between the parties for sale and purchase of energy will be denominated in the official currency of the Russian Federation. The Tariff to be paid to the Company by the Administration under the Agreement will include the following components:

A) The Fixed Capacity Charge for Heat Plant Component (fixed monthly charge payable only during the heating seasons to be agreed upon between the Administration and the Company):

Debt service,

Fixed maintenance costs,

Minimum rate of return on equity capital, based on a target rate of return on equity (allocated to heat plant investment) of [LATER]% per annum.

Other fixed costs, including insurance (see section 23.5 of PPA), property taxes, permitting fees, payments for government guarantees, and other taxes and duties.

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B) Energy Charge for Heat Component (charge per GCal based on plant despatch)

Cost of fuel, allowing a pass-through of all fuel costs incurred to meet dispatch requirements,

Variable O&M costs, allowing for recovery of all variable operations and maintenance costs incurred to meet dispatch and capacity requirements,

Other fees, to ensure recovery of all costs incurred in response to the dispatcher's requirements of the plant, including payments for:

A. Spinning Reserve

There is an added cost for fuel and operation and maintenance for providing spinning reserve. A clause in the Agreement shall address this issue.

B. Frequent Starts

There is a cost in shutting down and starting up units. The cost of expected starts shall be included in determining the initial base energy price and price adjustment provided for increased frequency of starts due to system requirements.

10.2 Penalties during Ongoing Plant Operation

10.2.1 Penalties Payable by the Administration

Under the proposed Agreement, the Administration is bound to pay the Capacity Charge for the heat plant investment, during specified heating seasons, regardless of energy used. This capacity charge is also payable in case of plant unavailability resulting directly from fuel supply interruptions, which are considered in this agreement as a force majeure event.

In the event of a default or delay in payment of either a planned capacity charge or energy consumed, the Administration is liable to pay the Company the amount due plus a penalty equivalent of

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[later]% of the balance due per day of payment delay. In such an event, Project Company may cease compliance with Despatch Requirements until all payments are made in full. During such period until resumption of normal operations and payments, the Administration shall be liable for full payments of the capacity charge.

10.2.2 Penalties Payable by Project Company

The Agreement will also provide for the collection of penalties by the Administration for failure to perform, as described below:

The Plant will be subject to periodic testing during Plant operation, based upon a mutually agreed testing schedule. In the event that the Plant fails to deliver its rated capacity, during any of the periodic testing, a penalty of [LATER] per GCal/hr of shortfall will be applied for each twelve (12) month period that the shortfall exists.

The Company may request a follow up test to demonstrate that the Plant is capable of providing the Guaranteed Net Output. The successful test that demonstrates that the plant is capable of producing the Guaranteed Net Output will not relieve the Company from its obligation to pay the stated penalty until that test. A new period of the said twelve months (12) will begin from the date of successful testing. Should the test demonstrate only a partially successful result where the actual net output has improved from the first test, but not to the extent that it meets the Guaranteed Net Output, the test shall not be given further consideration.

Penalties imposed on the project company for not meeting availability and performance requirements defined in the HPA would not be included in pass-through costs.

10.2.3 Price of Energy Generated During Start-Up

While the Plant is being tested and before the Completion Certificate is issued in accordance with the Agreement, there will be a certain quantity of energy produced during those tests. The price for this energy will be the energy charge.

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11.0 TARIFF ADJUSTMENTS RELATED TO COST

It will be necessary to specify in the Agreement which components of the energy price are subject to adjustment and what changed conditions would merit adjusting the price.

Some elements of fixed costs represented in the tariff will be adjusted as well as variable costs. The tariff will be adjusted every month on the following basis:

Fixed Capacity Charge for Heat Plant Component:

1) Debt service for foreign currency debt approved for the capital structure of the Company will be indexed to the currency of the debt,

2) for Fixed operation & maintenance costs, ruble expenses will be indexed to Russian inflation, and hard currency components indexed to the exchange rate applicable to the O&M costs, based on agreed upon standrads for what will constitue fixed O&M expenditures,

3) Minimum rate of return on equity, indexed to the foreign currency exchange rate, with a provision of adjustment to changes in tax regulations and other changes in law and regulations affecting investor profits,

4) Other fixed costs, including changes in insurance, property taxes, permitting fees, payments for government guarantees, and other taxes and duties, with indexation to foreign currency exchange rates for hard currency costs.

Heat Energy Charge Component:

1) Cost of fuel would be adjusted to allow a pass-through of all fuel costs incurred to meet dispatch requirements,

2) Variable O&M costs, allowing for recovery of all variable operations and maintenance costs, incurred to meet dispatch and capacity requirements, with adjustments in the necessary ruble payments to cover hard currency costs,

3) Other fees, would be adjusted as necessary to allow full recovery of costs, whether in domestic or foreign currency.

12.0 PAYMENT AND BILLING

The billing procedures will be designed to track the pricing provisions, the adjustments in prices and the reductions in price related to performance, including all supporting computations each month.

12.1 Computation of Bills

Monthly billing includes the following data and computations:

i. Energy delivered each hour of the month
ii. Computation of monthly Plant capacity payments (Fixed and Variable)
iii. Fuel costs in accordance with Section 10.0 of this agreement
iv. Computation of energy charge payment net of fuel costs
v. Computation of performance penalty
vi. Computation of price adjustments, if any.

12.2 Payment Procedure

At the outset of each monthly billing period, a tariff forecast shall be developed by the parties based on a forecasted increase in tariff adjustment indexes identified in 11.0, whereby the forecasted indexes for a given month shall be no less than the actual indices of the previous month. The Administration shall make payments based on the calculated indices and estimated energy purchases into a special escrow account. Upon issuance of a bill by the Project Company, the bill will be reconciled with payments to the account with additional payments to the Project Company by the Administration or a credit issued by the Project Company to the account for corresponding under or over-payments by the Administration to the account.

12.3 Notices

The Agreement should specify the maximum number of days after the month ends that the Company shall submit the billing computations to the Administration. It will set a limit in number of days following receipt of the bill that the Administration has to inform the Company of a billing error. The method and place of payment and the due date will be clearly set forth.

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13.0 INTERCONNECTION AND COMMUNICATION FACILITIES

It will be necessary for the parties to coordinate closely in the planning, design and inspection of heating interconnecting facilities. The facilities installed by the Company must be compatible with and meet the Administration's system needs.

14.0 OPERATION AND DISPATCH

14.1 Provisions will include a requirement that the Company perform according to best efforts to meet the Administration's schedule and for the facilities to respond to any demand whether automatic or otherwise from the Administration. It may be necessary to define what constitutes a request from the Administration. Provision will also be made for the Company to perform whatever interconnection facilities or generating equipment inspections or tests may be necessary following outages, replacement or repair. Forced outage definition notices and remedial measures associated with forced outages are included.

14.2 The Company shall specify the order in which the maintenance of various units of the facility are to be scheduled. The Administration will specify the month in which planned maintenance is to be accomplished. Modification of schedules set before the year are changed with mutual agreement.

14.3 The Agreement will provide a total of thirty (30) Calendar Days a year for planned maintenance. Should an unforeseen outage occur, other than that qualified under a force majeure, the Company may utilize the planned maintenance days on as need basis, but with consent of the Administration, prior to incurring any penalties.

15.0 METERING

Metering provisions will be included in the Agreement. Meters are provided, installed and maintained by the Administration and provisions in the Agreement should address the following:

1. Their exact location.

2. Right of access for all reasonable purposes by the parties.

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3. Meters are to be sealed by the Administration and the seals broken only for testing, inspection and adjustment and only when both parties have reasonable notice to have representatives present.

4. The frequency of inspecting and testing.

5. The accuracy tolerances to be allowed.

6. Action required and procedures, including billing adjustments, if meters are found to be deficient in accuracy.

16.0 COMPANY'S RECORDS

The Company shall maintain records during the term of the Agreement and for a period of three (3) years after final Tariff payment. However, records which relate to disputes, appeals, arbitration, litigation or the settlement of claims arising out of the performance of the Agreements shall be retained until such disputes, appeals, arbitrating, litigating or claims have been finally settled.

17.0 FORCE MAJEURE

A force majeure provision will be included.

Events that are covered (or not covered) by force majeure excusing performance will be defined. Notices in the event of a force majeure will be specified and the actions required of the non-performing party. Remedies of the affected party to the effects of certain force majeure will be addressed. Interruption of fuel supply may also be included in the definition of force majeure.

18.0 DISPUTE RESOLUTION

18.1 Operating Committee

The Administration shall assign a representative to the joint operating committee to be established between RAO EES Rossii and the Company, pursuant to the PPA, to address issues related to heat supply. The committee will be given broad duties and authority to investigate matters referred to it and resolve whatever problems it can.

18.2 Arbitration

a. Any dispute which may arise between the Administration and the Company concerning the interpretation of the Agreement and the performance of the various commitments thereof which cannot be settled amicably shall be submitted to Arbitration, in accordance with the rules of the [LATER]. The Arbitration place shall be [LATER].

b. The decision of the Arbitration Board which shall be reached by majority of votes with the provision that in the case of parity the decision for which the Chairman has voted shall prevail, must include the motives and arguments of the judgment and shall be binding, final and subject to no appeal, and both parties undertake to fulfill and execute the Arbitration's decision.

c. Any party may submit the decision in question to the Court of Competent jurisdiction in order to render it enforceable under the laws of the country of that Court.

d. Pending final decision of a dispute hereunder, the Company shall proceed diligently with the Project in accordance with the Administration's decisions, determinations, instructions and orders.

19.0 GUARANTEES, WARRANTIES, INDEMNITY AND LIABILITY

This provision sets forth the guarantees and warranties that each party makes to the other and the limits of each party as indemnitor to the other.

20.0 INSURANCE

20.1 Unless otherwise expressly provided in the Agreements, the Company shall, at its sole expense, take-out and maintain, in effect, at all times during the performance of the Agreements and until the Company and its contractors of each tier have demobilized, insurance coverage as set forth below. All insurances shall be placed in accordance with the laws of Russia.

20.2 Not less than ten (10) Calendar Days before commencing work at the Site, the Company shall deliver to the Administration certificates of insurance identified

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on their face as to project name and signed by the insurance company or its authorized representative, as evidence that policies providing such coverage and limits of insurance are in full force and effect. Such insurance shall provide that the insurance carrier shall furnish the Administration with written notice at least thirty (30) Calendar Days prior to the effective day of any material change, cancellation or non-renewal of the insurance.

21.0 DISCLAIMER

The Company, having represented itself as a qualified entity, through engagement of other contractors, having expertise in different areas in which the Company is required to perform under the Agreements, agrees that it has investigated all related aspects of the Project and the payment under the Tariff represents total compensation for all services and conditions of the Project.

22.0 ASSIGNMENT

There will be a prohibition against the assignment or disposition of the Project Facility or responsibility under the Agreement or interest without the express consent of the other party. Appropriate definitions and notice requirements will be provided.

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APPENDIX G

PRINCIPLES OF THE FUEL SUPPLY AGREEMENT

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PRINCIPLES OF THE FUEL SUPPLY AGREEMENT*

By and Between

KubanGRES Co.

and

RAO Gasprom

* Principles recommended by Consultants, currently undergoing review by all parties 12/04/95

FUEL SUPPLY AGREEMENT OUTLINE
TABLE OF CONTENTS

1. INTRODUCTORY STATEMENTS

This first article of the Fuel Supply Agreement (Agreement) identifies Kuban Gres Co. (The Company) located in the Village of Mostovskoy in Krasnodar Krai, Russia, and RAO Gasprom (the Supplier) as the contracting parties and shall state that, under this Agreement, fuel required by the Plant shall be sold to the Company by the Supplier. This section may state in the form of "whereas" clauses all the steps the parties have accomplished or intend to take upon signing the Agreement.

2. DEFINITIONS

2.1 Defined terms shall be provided for convenience and to be precise without repetition in the contract wording. Defined terms are limited only by the desires of the contracting parties.

2.2 The following words and expressions shall have the following meanings:

- "Agreement(s)" - means the contracts and documents between the Company and the Supplier or third parties.
- "Approved" or "Approval" - means approved by or approval of the Company unless otherwise stated. All approvals shall be in writing.
- "Calendar Day" or "Days" - means consecutive days, including weekends and Holidays.
- "Commercial Operation Date" - shall have the meaning attributed thereto in the Power Purchase Agreement.
- "Company Meter" means the flow meter installed at the Delivery Point to measure the quantity of fuel delivered to the Delivery Point.
- "Complex Fuel Transmission Facilities" - All the facilities located inside of the jobsite of the plant, to be constructed by or for the Project Company to enable it to receive fuel in accordance with this Agreement, plus the Metering System.

- "Delivery Point" means the point at the Complex at which fuel is delivered to the Company Meter.
- "Discrepancy Amount" means the amount of any invoice, or part thereof, which is disputed by the Company.
- "Escrow Account" means the escrow account established pursuant to the Escrow Agreement for the purpose of receiving sums in dispute under this Agreement.
- "Force Majeure" shall have the meaning defined in this agreement.
- "Guarantee" means the Guarantee given by the Company.
- "Interconnection Facilities" - All the facilities located outside of the jobsite of the plant constructed by or for RAO Gasprom to enable it to deliver fuel in accordance with this Agreement, plus the Metering System.
- "Month" means a calendar month according to the Gregorian calendar.
- "Net Electrical Output" means net energy delivered by the Company for sale to RAO under the Power Purchase Agreement.
- "PPA" or "Power Purchase Agreement" means the agreement between th Company and RAO EES Rossii for the purchase of power from the Complex.
- "Project Company" - means the Russian Joint Stock Company Kuban GRES established by a group to undertake the Project activities in accordance with the Agreements.
- "Site or Jobsite" - means the land and other places provided by the Krasnodar Krai and Mostovskoy Administrations on, under, or through which the Project is constructed and the work is executed or carried out, and any other lands or places provided by RAO for the purpose of the Agreements, together with such other places as maybe specifically designated in the Agreements as forming part of the Site or Jobsite.

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- "Supplier" - means the Russian Joint Stock Company Gasprom which owns and operates Russia's natural gas transmission and distribution networks, and in this context includes Kuban Gasprom.

- "Supplier Meter" means the flow meter installed at the Supply Point to measure the quantity of fuel delivered through the Supply Point.

- "Required Commissioned Date" means, with respect to each Unit, the date specified in the Power Purchase Agreement as the date on which such Unit is required to be Commissioned or such later date as may be determined by the Parties in accordance with the Power Purchase Agreement.

- "Required Completion Date" means the date sixty (60) Days prior to the Scheduled Commissioned Date.

- "Scheduled Commissioned Date" shall have the meaning attributed thereto in the Power Purchase Agreement.

- "Cubic Meter 1,000 kilograms of fuel, being the weight in air determined by multiplying the density of fuel by the measured volume thereof corrected to a standard temperature of 15 degrees centigrade.

- "Unit" shall have the meaning ascribed thereto in the Power Purchase Agreement.

Any terms not defined here shall have the meanings ascribed thereto in the Power Purchase Agreement, as applicable.

2.3 Singular and Plural

Words importing the singular only also include the plural and vice versa where the context requires.

3. PURCHASE AND SUPPLY OF FUEL FUEL

3.1 The term of this Agreement begins at the effective date of the Agreement and ends after a period of 30 years. The provisions applicable to the operation of

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the Plant shall become effective when the construction of the Plant has been completed and the Completion Certificate has been issued. The construction period shall be in accordance to Schedule 1 in the PPA.

3.2 Subject to the terms and conditions of this Agreement, the Company shall purchase from Supplier and Supplier shall sell to the Company all the Company's requirements for Natural Gas for the Complex during the term of this Agreement, to meet testing, and availability and despatch requirements defined in Schedule 1 of the PPA.

3.3 Supplier shall deliver to the Delivery Point such quantities of Natural Gas as may from time to time be requested by the Company in accordance with this Agreement.

3.4 Supplier shall ensure that Natural Gas supplied by it to the Company complies with the Specifications.

3.5 Company may not purchase Natural Gas under the terms of this agreement for purposes other than for meeting testing and availability and despatch requirements as identified in Schedule 1.

3.6 Company shall have right to modify this agreement, and Supplier be relieved of its long term supply responsibilities, in the event that it is agreed that a third party supplier will supply fuel to the project under separate agreement, and through access to existing facilities of the Supplier.

4. FACILITIES TO BE PROVIDED BY THE COMPANY

4.1 The Company shall, at its own cost and expense and not later than sixty (60) Days prior to the Scheduled Date of the First Unit, design, construct and complete the Complex Fuel Transmission Facilities.

4.2 The Complex Facilities shall be developed, designed, insured, constructed and completed, owned, operated and maintained by the Company in accordance with internationally accepted Natural Gas industry engineering standards and specifications.

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5. FACILITIES TO BE PROVIDED BY SUPPLIER

Supplier shall, at its own cost and expense, develop, design, insure, construct and complete, own, operate and maintain the facilities, equipment and other Interconnection Facilities as are necessary to deliver fuel to the Delivery Point. Such facilities shall be in all respects compatible with the Complex Facilities to be constructed by the Company.

5.1 Construction Schedule for Complex

Within thirty (30) Days after the Effective Date, the Company will provide the Supplier with a schedule for the construction of the Complex showing the Required Completion Date and the Scheduled Date of each Unit of the Complex.

Not later than six (6) Months after the Effective Date, the Supplier shall deliver to the Company a detailed schedule for the design and construction of the facilities.

During the construction of the facilities, the parties hereto will provide each other with quarterly reports showing progress of construction of the facilities and the Complex, respectively.

5.2 Commissioning of Facilities

Not later than six (6) Months prior to the Required Completion Date, Supplier shall provide the Company with a commissioning program and a schedule of commissioning tests for the facility. The program shall make clear the requirements on the Company arising from the commissioning of the facility and the cooperation required between the parties. The schedule of tests shall provide detailed test procedures including reference to:

(a) commissioning and test-run of pump station

(b) hydrostatic test;

(c) testing of fuel

(d) commissioning, calibration and test-run of fuel metering stations.

5.3 Permits; Access to Site by Supplier Company

The Company shall grant to Supplier adequate and continuing rights for the purpose of fulfilling its obligation under this Agreement to enter the Site and any other real property owned or leased by the Company subject only to Supplier giving prior notice to the Company.

When on the Site, Supplier shall comply with all reasonable instructions of the Company and its Direct Contractors relating to the carrying out of any work on the Site and shall indemnify and hold the Company harmless from any loss or damage sustained by virtue of Supplier's negligence in the exercise of its rights pursuant to the extent that such loss or damage is not covered by insurance.

5.4 Insurance by Supplier Company

Supplier, at its sole cost and expense, shall obtain and maintain during the term of this Agreement the policies of insurance specified hereto in the amounts set forth therein and during the periods mentioned therein; provided however, that such amounts may be changed from time to time with the prior written consent of the Company, which consent may not be unreasonably withheld.

6. SCHEDULING OF QUANTITIES TO BE DELIVERED

6.1 Delivery

6.1.1 The point of delivery of the fuel will be at the Complex Interconnection Facilities. The Company retains title to and accepts all responsibility for fuel transmission and storage at the point of delivery and the Supplier on the other side of the point of delivery.

6.1.2 The Supplier shall have no claim, other than the Dedicated Pipeline Recovery Charge, if Company can not receive fuel in accordance with the mutually agreed energy delivery schedules due to an outage at the plant from the time at which the Company informs the Supplier of such outage.

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6.2 Scheduling

Preliminary scheduling of fuel delivery shall be on an annual basis for planning and budgeting purposes by both parties. The proposed schedule will be initiated by the Company for review by the Supplier sixty (60) Calendar Days before the year begins for timely exchange of information and comments. The schedule may be based upon historical record of the load demand for the previous year, with appropriate adjustment factor for the increase in demand for the coming year. Similarly the planned maintenance scheduling shall be in parallel with the preliminary delivery schedule, with the Company specifying the amount of time needed for planned maintenance for each generating set and the preferred sequencing.

A monthly schedule of hourly delivery requirements is provided by the Company prior to the beginning of each month. The Company will have flexibility to modify this schedule each day prior to the day of delivery because of unanticipated load demands. The Supplier will exercise best efforts to supply the hourly schedule fuel delivery.

7. PRICING

7.1 Price of Fuel

The price to be paid by the Company for fuel delivered by Supplier under this Agreement shall be the price per cubic meter for Natural Gas, expressed in Rubels per cubic meter. The Price for fuel paid by the Company shall have two components:

a) Tariff for Fuel; which will be equal to the market or regulated price for natural gas charged by the Supplier to other large industrial customers and utilities in the Krasnodar Region, plus

b) Dedicated Pipeline Recovery Charge; which will be fixed monthly charges by the Supplier for recovery of its investment in the dedicated interconnection mains and facilities which will be solely used for the delivery of natural gas to the jobsite. This charge will be calculated as

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an annuity based on a 20-year repayment of this investment by the Supplier, with a return on investment rate of [LATER]% and monthly adjustment to the domestic inflation rate (Index to be mutually agreed upon by the parties).

7.2 Flushing Charge

If, at any time after the first delivery of fuel by the Pipeline to the Complex:

(i) the Pipeline requires flushing with as a result of any action or inaction of Supplier (other than an action or inaction expressly permitted by this Agreement), Supplier shall flush the Pipeline and the costs thereof shall be borne by Supplier.

(ii) the Pipeline requires flushing with as a result of the failure of the Company to design, construct, operate or maintain the Complex to such standards as could reasonably be expected, Supplier shall flush the facility and the costs thereof shall be borne by the Company.

8. INVOICING AND PAYMENTS

8.1 Letter of Credit

(a) The Company shall establish a transferable, divisible, irrevocable letter of credit ("Letter of Credit") in favor of Supplier with a scheduled bank that is reasonably acceptable to the Company and Supplier for the purpose of making payments to Supplier Company for fuel delivered hereunder. The first such Letter of Credit shall be established at least forty-five (45) Days prior to the commencement of deliveries of fuel under this Agreement.

8.2 Invoicing and Payment

(a) The Supplier shall submit to the Company an invoice for fuel delivered at the end of each month to the Company pursuant to this Agreement. Supplier shall also submit the Company invoices for any other obligations owed by the Company to Supplier arising hereunder as and

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when such obligations arise. Supplier Invoices for fuel shall be based upon the reading from the Supplier Meter and shall be certified by an authorized officer of Supplier and the quantities of fuel to be invoiced shall be calculated in accordance with this Agreement.

(b) The Company shall pay an invoice amount to Supplier no later than fourteen (14) Days after the receipt by the Company of the invoice. On and after the fifteenth day after the receipt by the Company of the invoice, late payments shall bear interest at a rate per annum equal to the Bank Rate plus two (2) percent compounded semi-annually and shall be computed for the actual number of Days elapsed on the basis of a 365 Day per year.

8.3 Calculation

All deliveries shall be measured by Supplier through the Supplier's Meter at the Supply Point and recorded continuously by the Company through the Company Meter at the Delivery Point. The quantity delivered shall be confirmed Monthly in writing by the Company to Supplier as soon as reasonably possible after the end of the respective Month.

In the event that the quantity of fuel actually received at the Delivery Point is disputed, whether the readings of the Supplier Meter or the Company Meter are incorrect as to the quantity of fuel at the Supply Point or actually received at the Delivery Point, Supplier and the Company shall determine the actual quantity of fuel received at the Delivery Point and credit or debit an appropriate amount to the next invoice for fuel submitted to the Company.

8.4 Referral to Expert

Failure of Supplier to respond to the Company's notification of any Discrepancy Amount with three (3) Days after Supplier's receipt thereof, or if the Company is dissatisfied with the response of Supplier to such notification or if Supplier or the Company contests any Discrepancy Amount and the parties cannot agree on the correct amount of such invoice or any correction thereof within fourteen (14) Days after its presentation to the Company by Supplier, either party may require the disputed invoice to be referred to Expert Adjudication to establish

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whether the invoice is correct and whether the Company was required to pay the Discrepancy Amount or any other disputed amount to Supplier.

9. TESTING OF RESIDUAL FUEL

9.1 Where Performed

Sampling and testing of fuel to be delivered pursuant to this Agreement shall be done at the facility as soon as practicable after the receipt by Supplier of a shipment of fuel for the Company's account. All sampling and testing shall be performed by Supplier in accordance with the procedures set forth.

9.2 Company's Right to Reject Fuel

The Company shall accept any fuel ordered by the Company and delivered by Supplier that complies with the Specifications. If any fuel sampled and tested in accordance with the provisions hereof fails to comply with the Specifications, the Company may accept or reject the non-conforming fuel.

9.3 Company May Test

Upon reasonable prior request to Supplier, the Company's representatives may enter upon any premises or sites occupied by Supplier upon which fuel and equipment that may be utilized in the performance of this Agreement is stored or placed and take and/or test any samples of fuel in the presence of Supplier representatives.

10. MEASUREMENT OF QUANTITY DELIVERED

10.1 Meters to be Installed

The Supplier shall, at its own cost and expense, install and maintain the Supplier Meter at the Supply Point in accordance with specifications. The Company shall, at its own cost and expense, install and maintain the Company Meter at the Delivery Point in accordance with specifications.

10.2 Accuracy of Meters

All meters or metering devices installed pursuant shall provide continuous records of fuel delivered. The recording from the Supplier Meter shall constitute the definitive reading for the purpose of calculating the quantity or quantities of fuel delivered each Day by Supplier; provided, however, that if the difference between the readings obtained from the Supplier Meter and the Company Meter is in excess of plus or minus 0.15 percent.

10.3 Records

Supplier and the Company shall furnish to each other all print-outs and chart recordings of their respective metering devices, and in the case of Supplier together with the invoice to which such print-outs and recordings relate. The Company and Supplier shall be given reasonable notice of, and be entitled to have a representative present during, the taking or re-taking of any measurements or meter readings.

10.4 Seals

All meters or metering devices used for the purpose of taking of measurements or readings shall be sealed.

11. MAINTENANCE AND REPAIR

11.1 The Supplier and the Company shall consult at least thirty (30) Days prior to the Scheduled Commissioned Date for the First Unit and at least ninety (90) Days prior to the commencement of each Year commencing with the Year following the Commercial Operations Date, for the purpose of agreeing a coordinated inspection and maintenance program of the facilities constructed. Such program shall be consistent with the requirements of the Complex, the requirements of the facility, and the Company's operations and maintenance obligations under the Power Purchase Agreement.

11.2 Supplier and the Company shall immediately consult in the event any unscheduled maintenance or repair is required to be done on the Pipeline or the

Complex to ensure the minimum possible disruption on the operation of the Complex and the Pipeline.

12. FORCE MAJEURE

A force majeure provision will be included to cover the following events:

- Force majeure - Natural
- Fore majeure - Political Internal or Government Involved
- Force majeure - Political External

Events that are covered (or not covered) by force majeure excusing performances will be defined.

Notices in the event of a force majeure will be specified and the actions required of the non-performing party. Remedies of the affected party to the effects of certain force majeure will be addressed.

13. PENALTIES, LIQUIDATED DAMAGES AND INDEMNITY

13.1 Failure by Supplier to Complete Facility

The Supplier hereby undertakes to indemnify the Company for any costs, damages, losses or penalties (including reasonable legal expenses) incurred by the Company insofar as such costs, damages, losses or penalties are directly attributable to the failure of Supplier to complete the construction of the facility by the Required Completion Date.

13.2 Failure by Supplier to Deliver Fuel

The Supplier shall be liable to make Company whole for any costs, penalties, damages, and loss of revenues resulting from shortfalls in required fuel deliveries.

13.3 Failure by the Company to Complete Complex

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If the Company has not completed construction of any Unit by the Scheduled Date of such Unit as initially set forth, then the Company shall pay to Supplier as liquidated damages for delay.

14. INDEMNITY

14.1 The Supplier will bear responsibility for loss of or damage to property, death or injury to person and all expenses relating thereto (including without limitation reasonable legal fees) suffered by, or liability for which is attributed to, the Company and/or its Contractors in connection with the Project resulting from any negligent act or omission of Supplier.

14.2 The Company will bear responsibility for loss of or damage to property, death or injury to person and all expenses relating thereto (including without limitation reasonable legal fees) suffered by, or liability for which is attributed to, Supplier in connection with the Project resulting from any negligent act or omission of the Company and/or its Contractors, without recourse to Supplier.

14.3 The indemnified party shall have the right, but not the obligation, to contest, defend and litigate, and to retain counsel of its choice in connection therewith, any claim, action, suit or proceeding by any third party alleged or asserted against such party in respect of, resulting from, related to or arising out of any matter for which it is entitled to be indemnified hereunder, and the reasonable coast and expense thereof shall be subject to the indemnification obligations of the indemnifying party.

SCHEDULE 1

SPECIFICATIONS FOR AND TESTING OF FUEL

Specification	Unit of Measurement	Value	IP Test Method	ASTM Test Method

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SCHEDULE 2

FACILITIES TO BE PROVIDED BY THE COMPANY

1. Pipeline termination flange as specified by Supplier.

2. Space for installation of termination valves, pipework, pig collection and any monitoring facility.

3. Locking Isolating Valve on the Company side of terminating flange.

4. Fuel flow meter.

5. Meter test and calibration facility.

6. Such other facilities and equipment as shall be necessary to construct and operate the Complex Facilities.

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SCHEDULE 3

FACILITIES TO BE PROVIDED BY SUPPLIER

1. Pipeline including thermal insulation and outer wrap, temperature monitoring.

2. Flow meter.

3. Facility for the Company's flow meter if required.

4. Valves and pipework for separation of storage tanks Supply Point and Delivery Point.

5. Meter test and calibration facilities.

6. Such other facilities and equipment as shall be necessary to construct and operate the Pipeline.

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APPENDIX H

CAPITAL COST BREAKDOWN

900 MW KRASNODAR GRES

PROJECT: KRASNODAR GRES
DESCRIPTION: 900MW GAS FIRED POWER PLANT
LOCATION: MOSTOVSKOY, RUSSIA

SUMMARY

BURNS and ROE ENTERPRISES, INC.

W.O. # 05826-007-07-0000-041

CODE	DESCRIPTION	QTY	UNIT	CATEGORY COSTS UNIT MANHOURS	TOTAL MANHOURS	TOTAL LABOR COST	MATERIAL UNIT	TOTAL MATERIAL	U.S. REFERENCE EQUIPMENT COST	EQUIPMENT COST DOMESTIC	FOREIGN	TOTAL COSTS
2000	SITE CLEARING TO SUBGRADE:											
	CLEAR & GRUB	128	HCTRS	300	38,400	67,200						67,200
	REMOVE AND STOCK TOPSOIL	532,500	CM	0.20	106,500	186,375						186,375
	BORROW FILL	1,292,000	CM	1.02	1,317,840	2,306,220						2,306,220
	PLACE STOCKPILED TOPSOIL	102,400	CM	0.50	51,200	89,600						89,600
	HAUL STOCKPILED TOPSOIL	430,100	CM	0.32	137,632	240,856						240,856
	EARTHWORK FROM SUBGRADE:											
	EXCAVATION	106,000	CM	0.32	33,920	59,360						59,360
	BACKFILL	58,000	CM	1.00	58,000	101,500						101,500
	HAUL & DISPOSE OVERBURDEN	54,000	CM	0.32	17,280	30,240						30,240
	CRUSHED STONE	6,000	CM	1.00	6,000	10,500	6	36,000				46,500
	UTILITY EXCAVATION	35,000	CM	0.32	11,200	19,600						19,600
	UTILITY BACKFILL	15,000	CM	1.00	15,000	26,250						26,250
	UTILITY HAUL & DISPOSE OVERBURDEN	15,000	CM	0.32	4,800	8,400						8,400
	UTILITY CRUSHED STONE	5,000	CM	1.00	5,000	8,750	6	30,000				38,750
	SITE DEVELOPMENT:											
	PAVING:											
	250MM CRUSHED STONE BASE	20,000	CM	1.00	20,000	35,000	6	120,000				155,000
	100MM ASPHALT CONCRETE BASE	8,000	CM	0.50	4,000	7,000	5	40,000				47,000
	50MM ASPHALT WEARING COURSE	4,000	CM	0.50	2,000	3,500	7	28,000				31,500
	150MM CRUSHED STONE SURFACING @ SWITCHYARD	22,500	CM	1.00	22,500	39,375	6	135,000				174,375
	RAILROAD SPUR (BALLAST, RAILS & ACCESSORIES)	4,000	M	15.00	60,000	105,000	50	200,000				305,000
2000	STORM DRAINAGE:											
	EXCAVATION	55,000	CM	0.32	17,600	30,800						30,800
	BACKFILL	34,000	CM	1.00	34,000	59,500						59,500
	HAUL & DISPOSE OVERBURDEN	22,500	CM	0.32	7,200	12,600						12,600
	CRUSHED STONE	1,500	CM	1.00	1,500	2,625	6	9,000				11,625
	FORMWORK	1,650	SM	22	36,300	63,525	0.5	825				64,350
	REINFORCING STEEL	110	MTONS	180	19,800	34,650	300	33,000				67,650
	CONCRETE	1,600	CM	10	16,000	28,000	45	72,000				100,000
	CONCRETE LINING	1,800	CM	4	7,200	12,600	55	99,000				111,600
	1500MM DIAMETER CONCRETE PIPE	175	M	2	350	613	15	2,625				3,238
	1200MM DIAMETER CONCRETE PIPE	340	M	2	680	1,190	13	4,420				5,610
	CHAIN LINK FENCE WITH GATES & POSTS	5,600	M	1.5	8,400	14,700	4	22,400				37,100
	GUARDRAIL & POSTS	1,000	M	1.5	1,500	2,625	4	4,000				6,625
	SHRUBS & TREES	500	EA	10	5,000	8,750	50	25,000				33,750
	DIVERGENT CANAL:											
	EXCAVATION	96,000	CM	0.32	30,720	53,760						53,760
	50MM CRUSHED STONE BEDDING	350	CM	1.00	350	613	6	2,100				2,713
	HAUL & DISPOSE OVERBURDEN	96,000	CM	0.32	30,720	53,760						53,760
	CONCRETE LINING	2,000	CM	4	8,000	14,000	55	110,000				124,000
	WELDED WIRE REINFORCING STEEL	8,000	SM	1	8,000	14,000	3	24,000				38,000
	EXPANSION JOINT FILLER AND SEALER	4,100	M	0.8	3,280	5,740	2	8,200				13,940
	WATER WELLS	3	EA	500	1,500	2,625	1,000	3,000				5,625
	TOTAL SITEWORK				2,149,372	3,761,401		1,008,570				4,769,971

PROJECT: KRASNODAR GRES
DESCRIPTION: 900MW GAS FIRED POWER PLANT
LOCATION: MOSTOVSKOY, RUSSIA

SUMMARY

BURNS and ROE ENTERPRISES, INC.

W.O. # 05826-007-07-0000-041

CODE	DESCRIPTION	QTY	UNIT	UNIT MANHOURS	TOTAL MANHOURS	TOTAL LABOR COST	CATEGORY COSTS MATERIAL UNIT	TOTAL MATERIAL	U.S. REFERENCE EQUIPMENT COST	EQUIPMENT COST DOMESTIC	FOREIGN	TOTAL COSTS
3000	CONCRETE:											
	FORMWORK	18,128	SM	20	362,560	634,480	2.0	36,256				670,736
	REINFORCING STEEL	2,413	MTONS	180	434,340	760,095	300	723,900				1,483,995
	CONCRETE	32,901	CM	10	329,010	575,768	45	1,480,545				2,056,313
	ELEVATED FORMWORK	1,697	SM	40	67,880	118,790	2.0	3,394				122,184
	ELEVATED REINFORCING STEEL	182	MTONS	200	36,400	63,700	300	54,600				118,300
	ELEVATED CONCRETE	1,837	CM	15	27,555	48,221						48,221
	METAL DECKING	1,900	SM	33	62,700	109,725	5	9,500				119,225
	PRECAST ROOF PLANKS	965	SM	30	28,950	50,663	45	43,425				94,088
	CONCRETE STAIRS	8	CM	30	240	420	45	360				780
	PRECAST ROOF TOPPING	16	CM	10	160	280	45	720				1,000
	SLAB ON GRADE CONCRETE	2,530	CM	4	10,120	17,710	45	113,850				131,560
	SLAB ON GRADE REINFORCING STEEL	196	MTONS	100	19,600	34,300	300	58,800				93,100
	SLAB ON GRADE VAPOR BARRIER	12,468	SM	0.1	1,247	2,182	1	12,468				14,650
	EXPANSION JOINT FILLER AND SEALER	3,880	M	1.0	3,880	6,790	2	7,760				14,550
	ELEVATED SLAB FLOOR SEALER	3,300	M	0.3	859	1,503	3	8,940				10,442
	TOTAL CONCRETE	37,292	CM3		1,385,500	2,424,626		2,554,518				4,979,144
				37.15								
4000	MASONRY:											
	CONCRETE MASONRY UNITS:											
	100MM WIDE	2,550	SM	6.60	16,830	29,453	7	17,850				47,303
	200MM WIDE	10,735	SM	7.50	80,513	140,897	11	118,085				258,982
	300MM WIDE	3,305	SM	9.00	29,745	52,054	15	49,575				101,629
	TOTAL MASONRY	16,590	SF		127,088	222,403	33	185,510				407,913
5000	METALS:											
	STRUCTURAL STEEL:	4,263	MTONS	80.00	341,040	596,820	800	3,410,400				4,007,220
	TOTAL STRUCTURAL STEEL	4,263	MTONS		341,040	596,820		3,410,400				4,007,220
	MISCELLANEOUS STEEL (STAIRS, EMBEDS, GRATING):	634	MTONS	120.00	76,116	133,203	900	570,870				704,073
	TOTAL MISCELLANEOUS STEEL	634	MTONS		76,116	133,203		570,870				704,073
	METAL DECKING:	28,470	SM	1.07	30,463	53,310	18	512,460				565,770
	TOTAL METAL DECKING	28,470	SM		30,463	53,310		512,460				565,770
	ANCHOR BOLTS:	80	MTONS	150	12,030	21,053	1,500	120,300				141,353
	TOTAL ANCHOR BOLTS	80	MTONS		12,030	21,053		120,300				141,353
	TOTAL METALS				459,649	804,386		4,614,030				5,418,416
6000	WOOD and PLASTICS:											
	ROUGH & FINISH CARPENTRY	1	LS	30000.00	30,000	52,500	15,000	15,000				67,500
	TOTAL WOOD and PLASTICS				30,000	52,500		15,000				67,500
7000	MOISTURE/THERMAL PROTECTION:											
	BUILT-UP ROOFING INCLUDING INSULATION:	25,685	SM	1.92	49,315	86,302	5	128,425				214,727
	TOTAL MOISTURE-THERMAL PROTECTION				49,315	86,302		128,425		ERR	ERR	214,727
8000	DOORS and WINDOWS:											
	DOORS, FRAMES, WINDOWS, OVERHEAD DOORS, LOUVERS	1	LOT	21806.00	21,806	38,161	260,900	260,900				299,061
	TOTAL DOORS and WINDOWS				21,806	38,161		260,900				299,061
9000	FINISHES:											
	WALLS, FLOORS, PAINTING & FIREPROOFING	1	LOT	259308.00	259,308	453,788	252,069	252,069				705,857
	TOTAL FINISHES				259,308	453,788		252,069				705,857
10000	SPECIALTIES:											
	TOILET PARTITIONS, LOCKERS, PLUMBING FIXTURES	1	LOT	7748.00	7,748	13,559	29,082	29,082				42,641
	TOTAL SPECIALTIES				7,748	13,559		29,082				42,641
11000	EQUIPMENT:											
	LOADING DOCK , WASTE HANDLING, FOOD SERVICE, MEDICAL	1	LOT	13500.00	13,500	23,625	38,000	38,000				61,625
	TOTAL EQUIPMENT				13,500	23,625		38,000				61,625
12000	FURNISHINGS:											
	OFFICE & PLANT FURNITURE	1	LOT	1000.00	1,000	1,750	6,000	6,000				7,750
	TOTAL FURNISHINGS				1,0[illegible]	1,750	6,000	6,000				7,750
	[illegible]L CIVIL SECTIONS 2 THRU 12				4,504,[illegible]	7,882,500		9,092,104				[illegible]74,603

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PROJECT: KRASNODAR GRES
DESCRIPTION: 900MW GAS FIRED POWER PLANT
LOCATION: MOSTOVSKOY, RUSSIA

SUMMARY

BURNS and ROE ENTERPRISES, INC.

W.O. # 05826-007-07-0000-041

CODE	DESCRIPTION	QTY	UNIT	CATEGORY COSTS: UNIT MANHOURS	TOTAL MANHOURS	TOTAL LABOR COST	MATERIAL UNIT	TOTAL MATERIAL	U.S. REFERENCE EQUIPMENT COST	EQUIPMENT COST: DOMESTIC	FOREIGN	TOTAL COSTS
15000	MECHANICAL SECTION											
	MECHANICAL EQUIPMENT											
	COMBUSTION TURBINE GENERATOR	4	EACH	40,000	160,000	440,000					120,000,000	120,440,000
	HRSG'S	4	EACH	160,000	640,000	1,760,000					34,500,000	36,260,000
	STEAM TURBINES	2	EACH	30,000	60,000	165,000					27,000,000	27,165,000
	CONDENSER (BAROMETRIC, SPRAY TYPE)	2	EACH									
	H R S G BYPASS STACK (STAINLESS STEEL)	4	EACH								INCL. IN C.T.	
	AIR COOLED CONDENSER COOLING TOWER	2	EACH	100,000	200,000	550,000			2,857,143	2,000,000	26,000,000	28,550,000
	MAIN STACK (ONE FLUE)	1	EACH	182,285	182,285	501,284	264,450	264,450				765,734
	DOMESTIC HOT WATER HEATERS	1	EACH	3,200	3,200	8,800			100,000	58,567		67,367
	BRIDGE CRANES, 90 MTONS, 25 METER SPAN	2	EACH	3,000	6,000	16,500			600,000	499,850		516,350
	BRIDGE CRANES, 54 MTONS, 25 METER SPAN	2	EACH	1,400	2,800	7,700			150,000	124,978		132,678
	BOILER FEED PUMPS - HIGH PRESSURE	6	EACH	125	750	2,063			3,000,000	2,000,000		2,002,063
	BOILER FEED PUMPS - LOW PRESSURE	6	EACH	110	660	1,815			250,000	150,000		151,815
	CONDENSATE PUMPS	12	EACH	110	1,320	3,630			600,000	420,000		423,630
	CONDENSATE POLISHER SYSTEMS	2	EACH	7,500	15,000	41,250			4,000,000	2,000,000		2,041,250
	DEMINERALIZED WATER PUMP	4	EACH	110	440	1,210			500,000	300,000		301,210
	VACUUM PUMPS	4	EACH	110	440	1,210			400,000	250,000		251,210
	DISTRICT HEATING WATER PUMPS	3	EACH	110	330	908			550,000	375,000		375,908
	CLOSED COOLING WATER PUMPS	3	EACH	110	330	908			600,000	420,000		420,908
	CIRCULATING WATER PUMPS	4	EACH	110	440	1,210			1,500,000	1,040,000		1,041,210
	FIRE PROTECTION PUMPS	2	EACH	110	220	605			106,000	74,000		74,605
	SERVICE WATER PUMPS	2	EACH	110	220	605			52,300	35,000		35,605
	POTABLE WATER PUMPS	2	EACH	110	220	605			10,000	7,000		7,605
	DEAERATOR (SPRAY TRAY TYPE, EACH FOR TWO HRSG)	2	EACH	105	210	578						578
	BLOWDOWN FLASH TANK	4	EACH	6,200	24,800	68,200			221,000	200,000		268,200
	CLOSED COOLING WATER HEAD TANK	2	EACH	6,200	12,400	34,100			110,200	77,000		111,100
	WASTE NEUTRALIZATION TANK	2	EACH	300	600	1,650			75,000	50,000		51,650
	DEMINERALIZED WATER STORAGE TANK	2	EACH	400	800	2,200			180,000	126,000		128,200
	OILY WASTE TANK	2	EACH	6,200	12,400	34,100			49,000	30,000		64,100
	CONDENSATE DRAIN TANK	2	EACH	6,200	12,400	34,100			22,500	15,000		49,100
	BOILER DRAIN TANK	4	EACH	6,200	24,800	68,200			68,000	48,000		116,200
	FUEL OIL TANKS (7,500 CUBIC METER VOLUME EACH)	2	EACH	6,200	12,400	34,100			750,000	500,000		534,100
	CLOSED COOLING WATER HEATER	1	EACH	7,000	7,000	19,250			750,000	500,000		519,250
	WATER PRETREATMENT SYSTEM	1	EACH	7,330	7,330	20,158			800,000	560,000		580,158
	BLOWDOWN HEAT EXCHANGER	4	EACH	10,000	40,000	110,000				INCLUDED		110,000
	MAKE UP WATER DEMINERALIZATION SYSTEM	1	EACH	17,100	17,100	47,025			1,500,000	1,100,000		1,147,025
	BOILER CHEMICAL FEED SYSTEM (EACH 3 SKIDS)	2	EACH	17,100	34,200	94,050			150,000	100,000		194,050
	PURIFIED WASTE WATER SYSTEM	1	EACH	30,000	30,000	82,500			2,500,000	1,800,000		1,882,500
	OIL SEPARATOR PACKAGE	1	EACH	10,000	10,000	27,500			85,000	60,000		87,500
	DOMESTIC WATER SYSTEM & POTABLE WATER TANK	1	EACH	20,000	20,000	55,000			300,000	210,000		265,000
	LAB EQUIPMENT	2	EACH	1,000	2,000	5,500			100,000	70,000		75,500
	H V A C SYSTEM	1	LOT	30,000	30,000	82,500			700,000	500,000		582,500
	AIR COMPRESSOR WITH RECEIVER	2	EACH	6,000	12,000	33,000			410,000	300,000		333,000
	AIR DRIER	1	EACH	5,000	5,000	13,750			115,000	75,000		88,750
	WELL PUMPS	4	EACH	110	440	1,210			20,000	14,000		15,210
	SUMP PUMPS	10	EACH	110	1,100	3,025			10,000	7,000		10,025
	DISTRICT HEAT HOT WATER BOILERS	2	EACH	3,155	6,310	17,353			3,000,000	2,200,000		2,217,353
	DISTRICT HEAT STEAM BOILERS	2	EACH	760	1,520	4,180			3,000,000	2,200,000		2,204,180
	TOTAL MECHANICAL EQUIPMENT				1,599,465	4,398,529			30,191,143	20,496,395	207,500,000	232,659,374

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PROJECT: KRASNODAR GRES
DESCRIPTION: 900MW GAS FIRED POWER PLANT
LOCATION: MOSTOVSKOY, RUSSIA

SUMMARY

BURNS and ROE ENTERPRISES, INC.

W.O. # 05826-007-07-0000-041

CODE	DESCRIPTION	QTY	UNIT	CATEGORY COSTS UNIT MANHOURS	TOTAL MANHOURS	TOTAL LABOR COST	MATERIAL UNIT	TOTAL MATERIAL	U.S. REFERENCE EQUIPMENT COST	EQUIPMENT COST DOMESTIC	FOREIGN	TOTAL COSTS
	PIPING AND ACCESSORIES											
	CRITICAL PIPING SYSTEMS :											
	MAIN STEAM (CHROME-MOLY ALLOY STEEL) :	167	MTONS		26,598	73,145		962,010				1,035,155
	INTERMEDIATE PRESSURE STEAM (CARBON STEEL) :	19	MTONS		10,722	29,486		80,069				109,555
	HIGH PRESSURE FEEDWATER (CARBON STEEL) :	36	MTONS		19,189	52,770		265,424				318,194
	COLD REHEAT (CARBON STEEL) :	35	MTONS		9,626	14,439		135,067				149,506
	HOT REHEAT (CHROME-MOLY ALLOY STEEL) :	79	MTONS		23,123	63,588		463,078				526,666
	CIRCULATING WATER (CARBON STEEL) :	600	MTONS		38,764	106,601		2,447,798				2,559,895
	DISTRICT HEATING SUPPLY & RETURN (CARBON STEEL) :	216	MTONS		56,605	155,664		507,417				663,081
	NON-CRITICAL PIPING (64 MM DIAMETER and LARGER)	350	MTONS	500	175,000	481,250	700	245,000				726,250
	NON-CRITICAL PIPING INSULATION 75MM CALSIL JACKETED	3,300	SM	14	46,200	127,050	43	141,900				268,950
	SMALL BORE PIPING (50 MM DIAMETER and SMALLER)	16,768	M	9	150,915	415,015	15	251,524				666,540
	TEMPORARY BLOWOUT PIPING (field erect)	20	MTONS	500	10,000	27,500	700	14,000				41,500
	CHEMICAL CLEANING	1	LOT	80,000	80,000	220,000	150,000	150,000				370,000
	LOW PRESSURE VALVES	307	EA	60	18,420	50,655	1,700	521,900				572,555
	SMALL DIAMETER VALVES	2,875	EA	6	17,250	47,438	260	747,500				794,938
	EXPANSION JOINTS	26	EA	116	3,016	8,294	586	15,236				23,530
	STRAINERS	81	EA	15	1,215	3,341	1,154	93,474				96,815
	REVERSE CURRENT VALVES	14	EA	200	2,800	7,700	19,000	266,000				273,700
	PIPE HANGERS AND SUPPORTS	1	LOT	65,000	65,000	178,750	310,000	310,000				488,750
	MISC PIPING SPECIALTIES	1	LOT	26,000	26,000	71,500	820,000	820,000				891,500
	CONTROL VALVES	90	EA	79	7,110	19,553	6,500	585,000				604,553
	SAFETY RELIEF VALVES	78	EA	25	1,950	5,363	660	51,480				56,843
	YARD PIPING	365	TONS	500	182,500	501,875	700	255,500				757,375
	YARD PIPING INSUL 75MM CALSIL JACKETED, H.TRACE AS REQ'	3,500	SM	26	91,000	250,250	56	196,000				446,250
	EQUIPMENT INSULATION 75MM CALSIL WITH JACKET	700	SM	14	9,800	26,950	43	30,100				57,050
	TOTAL PIPING AND ACCESSORIES	2,087	MTONS		1,191,294	2,938,175		9,555,477				12,499,148
15000	TOTAL MECHANICAL EQUIPMENT AND PIPING				2,790,759	7,336,703		9,555,477		20,496,395	207,500,000	245,158,522
	OTHER MECHANICAL											
	PLUMBING, ROOF & FLOOR DRAINS, FIRE PROTECTION	1	LOT	60,000	60,000	165,000	1,650,000	1,650,000				1,815,000
	TOTAL OTHER MECHANICAL				60,000	165,000		1,650,000				1,815,000
	TOTAL MECHANICAL SECTION 15				2,851,000	7,502,000		11,205,000		20,496,000	207,500,000	246,974,000

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PROJECT: KRASNODAR GRES
DESCRIPTION: 900MW GAS FIRED POWER PLANT
LOCATION: MOSTOVSKOY, RUSSIA

SUMMARY

BURNS and ROE ENTERPRISES, INC.

W.O. # 05826-007-07-0000-041

	CODE	DESCRIPTION	QTY	UNIT	CATEGORY COSTS: UNIT MANHOURS	CATEGORY COSTS: TOTAL MANHOURS	CATEGORY COSTS: TOTAL LABOR COST	CATEGORY COSTS: MATERIAL UNIT	CATEGORY COSTS: TOTAL MATERIAL	U.S. REFERENCE EQUIPMENT COST	EQUIPMENT COST: DOMESTIC	EQUIPMENT COST: FOREIGN	TOTAL COSTS
	16000	ELECTRICAL SECTION											
		ELECTRICAL EQUIPMENT											
		TOTAL BUILDING SERVICES	1	LOT	30,852	30,852	84,842		456,028				540,870
		TOTAL WIRE & CABLE	1	LOT	607,427	607,427	1,670,423		1,956,282				3,626,705
		TOTAL CONDUIT	1	LOT	429,671	429,671	1,181,595		473,380				1,654,975
		TOTAL ELECTRICAL MATERIAL	1	LOT	123,334	123,334	339,169		3,161,427				3,500,596
		TOTAL INSTRUMENTATION	1	LOT	49,683	49,683	136,628		39,195				175,823
		TOTAL MISC (LIGHTING PROTECTION, PA & PHONE SYSTEMS)	1	LOT	90,620	90,620	249,209		1,230,096				1,479,305
		TOTAL CABLE TRAY	1	LOT	127,585	127,585	350,859		154,428				505,287
		TOTAL TERMINATIONS	1	LOT	117,344	117,344	322,695		74,164				396,859
4	VNDR	MAIN TRANSFORMER 250MVA, 525/15.25KV	3	EA	666.667	2000.00	5,500	800,000		3,428,571	2,400,000		2,405,500
5	VNDR	MAIN TRANSFORMER 250MVA, 220/15.25KV	3	EA	666.667	2000.00	5,500	700000.00		3,000,000	2,100,000		2,105,500
6	VNDR	ISOPHASE/NO-SEC BUS	1	Pckg.s	58000.000	58000.00	159,500	1400000.00		2,000,000	1,400,000		1,559,500
6	VNDR	GENERATOR SWITCH FOR GAS TURBINE & STEAM TURBINE	6	EA	53.000	320.00	880	500000.00		4,285,714	3,000,000		3,000,880
7	VNDR	AUX. TRANSFORMER 16MVA, 15.75/6.3KVKV	4	EA	100.000	400.00	1,100	120000.00		685,714	480,000		481,100
11	VNDR	DCS SYSTEM	2	EA	4000.000	8000.00	22,000	1450000.00				2,900,000	2,922,000
12	VNDR	6KV SWITCHGEAR (11 ASSEMBLIES, 40 UNITS)	1	Pckg.s	16000.000	16000.00	44,000	1400000.00		2,000,000	1,400,000		1,444,000
13	VNDR	400V SWITCHGEAR (20 ASSEMBLIES)	1	Pckg.s	24000.000	24000.00	66,000	2600000.00		3,714,286	2,600,000		2,666,000
14	VNDR	MOTOR CONTROL CENTERS (40 ASSEMBLIES)	1	Pckg.s	24000.000	24000.00	66,000	1000000.00		1,428,571	1,000,000		1,066,000
17	VNDR	UPS SYSTEM (Batt.s,DC Pnl., Batt. Chrgr.)	2	Pckg.s	300.000	600.00	1,650	75000.00		214,286	150,000		151,650
19	VNDR	DC SYSTEM (w/ BATTERY & CHARGERS)	2	Pckg.s	1500.000	3000.00	8,250	150000.00		428,571	300,000		308,250
20	VNDR	RELAY PANEL & SYNC. PANEL	1	Pckg.s	800.000	800.00	2,200	150000.00		214,286	150,000		152,200
		TOTAL ELECTRICAL SECTION 16				1,715,636	4,718,000		7,545,000	21,400,000	14,980,000	2,900,000	30,143,000
		TOTAL DIRECT COST:CIVIL/MECH/ELECTRICAL				9,071,000	20,102,000		27,842,000		35,476,000	210,400,000	294,092,000

PROJECT: KRASNODAR GRES
DESCRIPTION: 900MW GAS FIRED POWER PLANT
LOCATION: MOSTOVSKOY, RUSSIA

SUMMARY

BURNS and ROE ENTERPRISES, INC.

W.O. # 05826-007-07-0000-041

CODE	DESCRIPTION	QTY	UNIT	CATEGORY COSTS UNIT MANHOURS	TOTAL MANHOURS	TOTAL LABOR COST	MATERIAL UNIT	TOTAL MATERIAL	U.S. REFERENCE EQUIPMENT COST	EQUIPMENT COST DOMESTIC	FOREIGN	TOTAL COSTS
	INDIRECT COSTS and GENERAL EXPENSE SECTION											
	FIELD STAFFING											
	SUPERVISION - ADMINISTRATIVE (12 PEOPLE)	540	MO	172	92,880	371,520						371,520
	SUPERVISION - CONSTRUCTION (12 PEOPLE)	540	MO	172	92,880	278,640						278,640
	OFFICE MANAGEMENT and CLERICAL (8 PEOPLE)	360	MO	172	61,920	185,760						185,760
	FIELD ENGINEERING (9 PEOPLE)	400	MO	172	68,800	206,400						206,400
	SAFETY AND INDUSTRIAL RELATIONS (6 PEOPLE)	270	MO	172	46,440	139,320						139,320
	QUALITY ASSURANCE (6 PEOPLE)	270	MO	172	46,440	139,320						139,320
	PROCUREMENT - JOB (6 PEOPLE)	270	MO	172	46,440	139,320						139,320
	RECRUITING/REPLACEMENT COSTS	1	LOT	5000	5,000	15,000						15,000
	O & M TRAINING	1	LOT								1,200,000	1,200,000
	TOTAL FIELD STAFFING				460,800	1,475,280					1,200,000	2,675,280
	INDIRECT CONSTRUCTION SERVICES and SUPPORT											
	SUBSURFACE INVESTIGATIONS	1	LS	2000.00	2,000	6,000	5,000	5,000				11,000
	SITE SURVEY	1	LS	5000.00	5,000	15,000	5,000	5,000				20,000
	CLEANUP - CONTINUOUS and FINAL	1	LS	65000.00	65,000	195,000	15,000	15,000				210,000
	WORKER TRAINING PROGRAM and FACILITY	1	LS	35000.00	35,000	105,000	15,000	15,000				120,000
	VENDOR REPRESENTATIVES/ADVISORS	1	LS	20000.00	20,000	60,000	100,000	100,000			2,000,000	2,160,000
	SAFETY CONSTRUCTION/LAYDOWN FENCING	1	LS	5000.00	5,000	15,000	10,000	10,000				25,000
	TESTING & CONSULTING - LAB SERVICES	1	LS	30000.00	30,000	90,000	15,000	15,000				105,000
	MATL HANDLING/BARGE/RAIL/ TRUCK to WAREHOUSE	1	LS	125000.00	125,000	375,000	500,000	500,000			3,000,000	3,875,000
	WEATHER PROTECTION	1	LS	10000.00	10,000	30,000	5,000	5,000				35,000
	GENERAL MAINTENANCE	1	LS	10000.00	10,000	30,000	5,000	5,000				35,000
	TOTAL INDIRECT CONSTR SERVICES and SUPPORT			307,000	307,000	921,000	675,000	675,000			5,000,000	6,596,000
	FACILITIES and UTILITIES											
	WORKER BASE CAMP	1	LS	105,000	105,000	315,000	400,000	400,000				715,000
	DIESEL GENERATOR SYSTEM / FUEL COSTS - TEMP. POWER	1	LS	15,000	15,000	45,000	20,000	20,000				65,000
	RECREATIONAL COMPLEX	1	LS	15,000	15,000	45,000	50,000	50,000				95,000
	CONSTRUCTION STAFF - BUILDINGS	1	LS	15,000	15,000	45,000	75,000	75,000				120,000
	WAREHOUSES - LAYDOWN AREA	1	LS	10,000	10,000	30,000	25,000	25,000				55,000
	FABRICATION FACILITIES	1	LS	10,000	10,000	30,000	20,000	20,000				50,000
	TEMPORARY POWER DISTRIBUTION SYSTEM	1	LS	5,000	5,000	15,000	25,000	25,000				40,000
	SITE/CAMP WATER - TEMP. DISTRIBUTION SYSTEM	1	LS	3,500	3,500	10,500	5,000	5,000				15,500
	SANITARY FACILITIES - FIELD	1	LS	6,000	6,000	18,000	2,000	2,000				20,000
	TEMPORARY ROADS	1	LS	10,000	10,000	30,000	5,000	5,000				35,000
	MEDICAL SUPPLIES	1	LS				10,000	10,000				10,000
	TOTAL FACILITIES and UTILITIES				194,500	583,500	237,000	637,000				1,220,500

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PROJECT: KRASNODAR GRES
DESCRIPTION: 900MW GAS FIRED POWER PLANT
LOCATION: MOSTOVSKOY, RUSSIA

SUMMARY

BURNS and ROE ENTERPRISES, INC.

W.O. # 05826-007-07-0000-041

CODE	DESCRIPTION	QTY	UNIT	CATEGORY COSTS UNIT MANHOURS	TOTAL MANHOURS	TOTAL LABOR COST	MATERIAL UNIT	TOTAL MATERIAL	U.S. REFERENCE EQUIPMENT COST	EQUIPMENT COST DOMESTIC	FOREIGN	TOTAL COSTS
	CONSTRUCTION EQUIPMENT											
	ERECT & DISMANTLE	1	LOT	40,000	40,000	120,000	10,000	10,000				130,000
	HAULING & TRANSPORTATION (LOCAL)	1	LOT	5,000	5,000	15,000	5,000	5,000				20,000
	CONSTRUCTION EQUIPMENT	1	LOT				2,000,000	2,000,000				2,000,000
	SCAFFOLDING	1	LOT	15,000	15,000	45,000	15,000	15,000				60,000
	EQUIPMENT OPERATORS(mechanical/electrical)	1	LOT	40,000	40,000	120,000						120,000
	CONCRETE/ASPHALT BATCH PLANTS with OPERATORS	1	LOT	40,000	40,000	120,000	45,000	45,000				165,000
	EQUIPMENT REPAIRS/PARTS	1	LOT	12,000	12,000	36,000	25,000	25,000				61,000
	FUEL, OIL & GREASE	1	LOT	12,000	12,000	36,000	100,000	100,000				136,000
	SMALL TOOLS & CONSUMABLES	1	LOT				50,000	50,000				50,000
	MOTOR POOL	1	LOT				100,000	100,000				100,000
	TOTAL CONSTRUCTION EQUIPMENT				164,000	492,000	2,350,000	2,350,000				2,842,000
	INSURANCE, TAXES, FREIGHT, PERMITS, OTHER											
	BUILDER'S RISK INSURANCE	1	LS				750,000	750,000				750,000
	VEHICLE INSURANCE	1	LS				50,000	50,000				50,000
	GENERAL LIABILITY INSURANCE/EPC	1	LS				50,000	50,000				50,000
	UMBRELLA INSURANCE	1	LS				250,000	250,000				250,000
	TARIFFS / VAT	1	LS									NOT INCLUDED
	RUSSIAN TAXES	1	LS									NOT INCLUDED
	BUILDING PERMITS	1	LS				100,000	100,000				100,000
	LICENSES	1	LS				25,000	25,000				25,000
	PAYMENT and PERFORMANCE BOND	1	LS				7,500,000	7,500,000				7,500,000
	FOREIGN SPARE PARTS (0.045% of Foreign Equipment Costs)	1	LS								9,337,500	9,337,500
	DOMESTIC SPARE PARTS (0.02% of Domestic Equipment Costs)	1	LS							709,520		709,520
	START-UP FUELS / CHEMICALS	1	LS	5,000	5,000	15,000	10,000	10,000				25,000
	DISPOSAL OF START-UP CHEMICALS	1	LS	5,000	5,000	15,000	5,000	5,000				20,000
	TOTAL INSURANCE, TAXES, FRINGES, PERMITS, OTHER				10,000	30,000		8,740,000		709,520	9,337,500	18,817,020
	TOTAL INDIRECT COSTS & GENERAL EXPENSES				1,136,000	3,502,000		12,402,000		710,000	15,538,000	32,151,000
	TOTAL DIRECT and INDIRECT COSTS				10,210,000	23,600,000		40,240,000		36,190,000	225,940,000	326,240,000
	ENGINEERING SERVICES											
	A/E DESIGN SERVICES	1	LOT				100,000	100,000		195,000	4,000,000	4,295,000
	A/E FIELD SUPPORT SERVICES	1	LOT				300,000	300,000		90,000	4,500,000	4,890,000
	MANAGEMENT and SUPERVISION of START-UP, TESTING	1	LOT				10,000	10,000		30,000	1,500,000	1,540,000
	TOTAL ENGINEERING SERVICES							410,000		315,000	10,000,000	10,725,000
	TOTAL DIRECT, INDIRECT & ENGINEERING SERVICE COSTS											336,970,000
	PROFIT & OFF SITE OVERHEADS	12.0%										40,436,000
	TOTAL COST											377,410,000
	TOTAL COST PER KILOWATT											$419

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APPENDIX I

TRANSMISSION SYSTEM REINFORCEMENT STUDY

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POWER TECHNOLOGIES, INC.

POWER TECHNOLOGY DEVELOPMENT COMPANY, INC.

KRASNODAR PROJECT

TRANSMISSION SYSTEM REINFORCEMENT

PTI Report #R90-95

Prepared by:

POWER TECHNOLOGIES, INC.

October 1995

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1. INTRODUCTION

The reinforcement of the Transmission System of Krasnodarsky Kray, located in the North Caucasus Region of the Russian Unified Power System, is due to the projected construction of the 900 MW Power Plant in Mostovskaya site. This Power Plant (quoted below as Krasnodarsky Power Plant) is supposed to have two combined cycle units. Each 450 MW unit comprises two 150 MW gas turbine generators and 150 MW steam turbine generator.

Transmission and substation additions needed have been preliminary defined and an assessment of transmission costs associated with implementation of this plant was accomplished at the first stage of the project.

At the second stage of the project, findings of the first stage have been checked by means of load flow, fault, and dynamic studies.

The work at the second stage of the Krasnodar Project has been fulfilled by the same team of American and Russian consultants as at the first stage.

2. TRANSMISSION AND SUBSTATION ADDITIONS

The Krasnodarsky Power Plant will be constructed at the new site where there is no substation so far. The 220 kV and 500 kV switch yards should be constructed, with 3*167 MVA autotransformer connection between them.

The first 450 MW Unit will be connected to 220 kV bus, the second -to 500 kV bus.

To deliver power to regional consumers at the voltage of 220 kV, three new 220 kV substations should be constructed: in Kurgannaya, Cheremushki, and Zilposelok.

The substation equipment which should be installed due to project consists of (Figure 1.1):

220 kV and 500 kV switch yards of the Krasnodarskaya Power Plant:

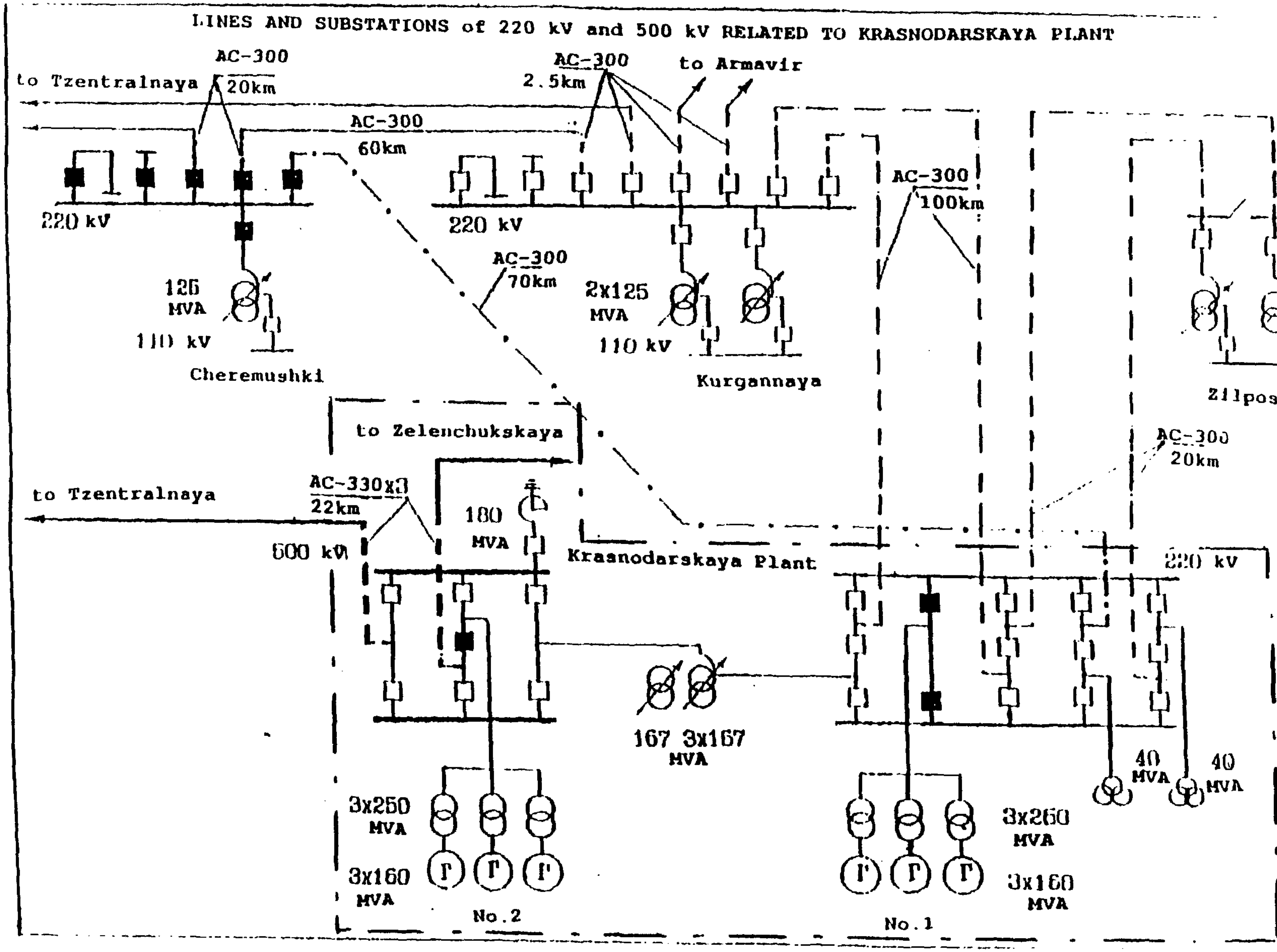
- 220 kV circuit breaker - 14 three-phase units
- 500 kV circuit breaker - 8 three-phase units
- 167 MVA 500/220 kV autotransformer - three single-phase units plus one spare unit
- 180 MVA 500 kV shunt reactor - one three-phase unit
- step-down 40 MVA 220/10 kV transformer - two three-phase units

new 220 kV substations in Cheremushki, Kurgannaya, and Zilposelok:

- 220 kV circuit breaker - 18 three-phase units
- 110 kV circuit breaker - 5 three-phase units
- step-down 125 MVA 220/110 kV transformer - 5 three-phase units.

The detailed studies undertaken at the second stage of the project did not reveal significant discrepancies in terms of transmission additions needed, with respect to the results of the first stage. Figure 1.2 depicts block diagram showing these additions as follows:

- Rerouting the existing 500 kV 310 km line going from Tzentralnaya to Zelenchukskaya via the 500 kV switch yard of the Krasnodarskaya Power Plant: 2*22 = 44 km
- New single-circuit 220 kV line from Krasnodarskaya Power Plant to Cheremushki substation: 70 km
- New double-circuit 220 kV line from Kurgannaya to Zilposelok via Krasnodarskaya Power Plant: 2*100+2*20 = 240 km
- Rerouting one circuit of the existing double-circuit 220 kV 185 km line going from Tzentralnaya to Armavir via Cheremushki: 2*20 = 40 km
- Rerouting both circuits of the same line via Kurgannaya: 4*2.5 = 10 km.



Notes:
- - - - - Lines needed for the Unit No.1
- . - . - Lines needed for the Unit No.2
□ Circuit breakers for the Unit No.1
■ Circuit breakers for the Unit No.2

Figure 1.1

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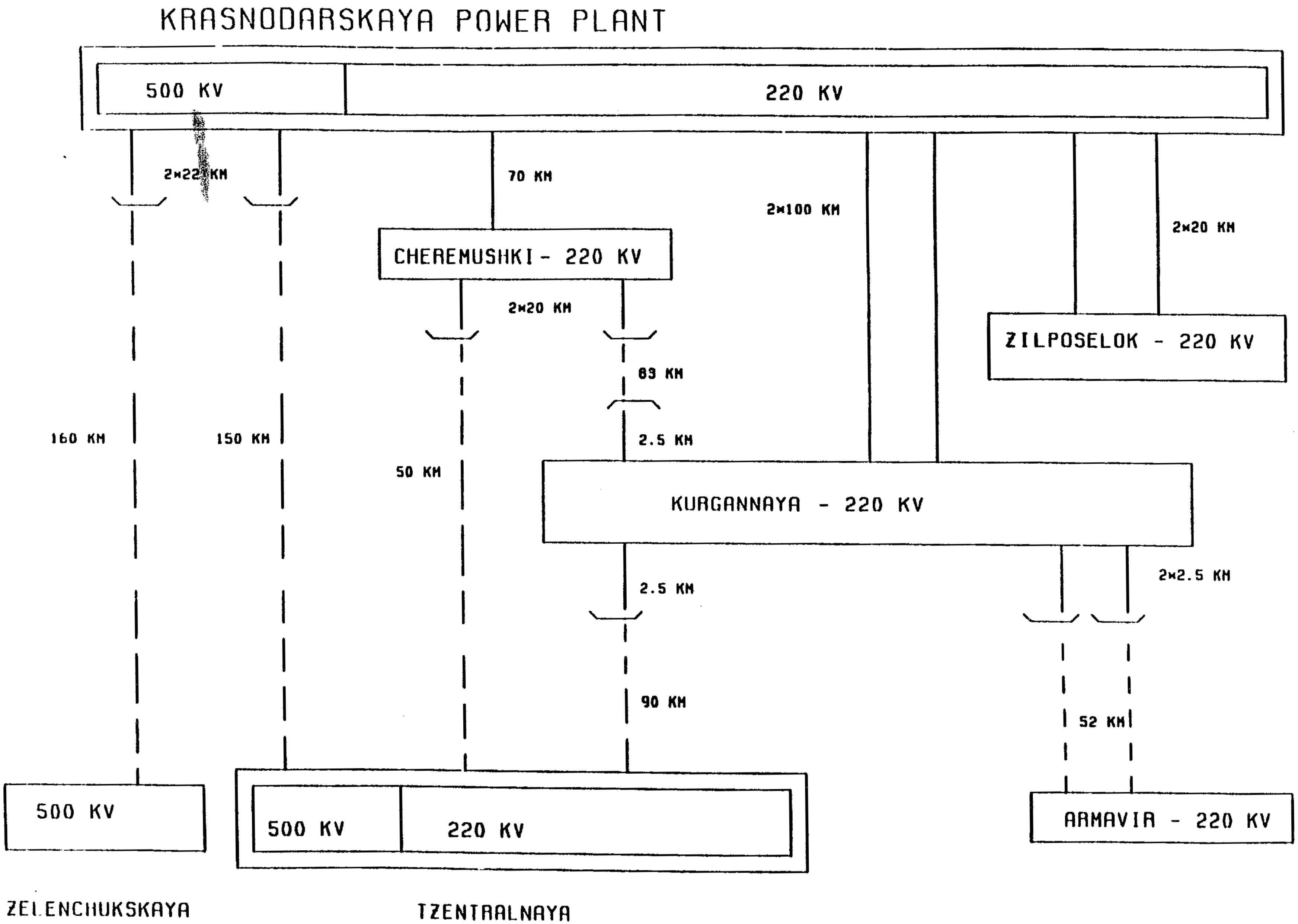


KRASNODAR TRANSMISSION REINFORCEMENT

Figure 1.2

DOTTED LINE: EXISTING TRANSMISSIONS

SOLID LINE: TRANSMISSIONS DUE TO PROJECT

3. BACKGROUND ASSUMPTIONS

At present the North Caucasus Interconnected Power System (IPS) is one of the most energy- and power-deficient systems within the Russian Unified Power System. Until recently this shortage was expected to be covered by construction of the Rostov Nuclear Power Plant (RNPP) and by power transmission from other regions of Russia. Nowadays the RNPP appears to be commissioned in a very remote future, if at all. As for wheeling of electricity to the North Caucasus from the rest of Russia by the existing electric ties via Ukrainian networks, the arrangement is considered, for a number of reasons, to be insufficiently reliable to assure normal functioning of the power industry of a region as important as the North Caucasus.

The interconnection between the North Caucasus IPS and the Center and Middle Volga IPS, now under construction, will make it possible to improve substantially the power supply of the North Caucasus. However, because of considerable uncertainty in development prospects of both the North Caucasus and especially the Transcaucasian republics whose utilities are connected to the North Caucasus IPS, it is hard to make an accurate prediction of future power and energy demands of the North Caucasus. On the other hand, right now the area under discussion suffers from ever increasing power supply difficulties. Therefore the construction of the above-mentioned interconnection tie had to be supplemented by development of the generating capacity of the IPS; thus several power plant projects were considered.

As a result of the first stage, a combined cycle steam-gas unit power plant of 900 MW comprising two 450 MW units was proposed to be constructed in Mostovskaya site.

The objective of this study is to investigate system issues relating to construction of the Krasnodarsky Power Plant. The primary goal is to appraise the power output scheme in terms of stability and reliability of the power plant and to determine the effect of the new power plant on stability and reliability of the Interconnected Power System as a whole. Additionally the study is to cover fault currents, automatic emergency control and relay protection matters.

The study has covered operating conditions corresponding to full-capacity and maintenance layouts both before and after implementation of the project, as well as transients caused by uncleared three-phase faults followed by disconnection of a number of the most loaded components.

For a greater ease of presentation, the study cases are designated by three-digit numbers of the k-m-p type, where:

k = 1, 2, 3, where 1 corresponds to the base (pre-project) case layout, 2 - to the project case, and 3 - to the project case with overloaded Krasnodarsky Power Plant generators;

m = 0, 1, ..., n, where corresponds to the full capacity layout, 1 etc. - to the maintenance and post-emergency layouts with respective network components disconnected;

p = 1 or 0, with or without power flow to Transcaucasia, respectively.

The principal parameters of operating conditions that characterize the loading and the voltage levels of the North Caucasus System's internal 500 kV ties and external 220 kV, 330 kV and 500 kV ties are given in respective drawings.

The investigated operating conditions for the base and project case layouts are given in Tables 2 and 3, with reference to the respective illustrating drawings.

4. LOAD FLOW STUDY FOR THE BASE (PRE-PROJECT) CASE

The North Caucasus Interconnected Power System comprises nine utilities, which are listed in Table 1.

The Year 2000 configuration of the North Caucasus IPS, which takes into account the external ties with the Center and Middle Volga IPS, now under construction, and those with Ukraine, existing at present, was taken to be the base case layout. Power systems of Transcaucasia and ties thereto were assumed to be as they were when the USSR disintegrated.

The estimates for 2000 show the maximum load of the Interconnected Power System to be 10,100 MW and the available generating capacity, 11,350 MW. Taking into account mandatory reserves and unused capacities, the actual generation is 8650 MW. Thus the total power deficiency for the IPS will be 1450 MW, to be distributed among the nine constituent utilities (power systems) as shown in Table 1.

TABLE 1

Commitments of Constituent Power Systems of the North Caucasus Interconnected Power System, MW

Power System	Pav1	Pidle	Pres	Pact.g	Pload	-/+
Rostov	3136	40	595	2501	3110	-609
Krasnodar	1288	-	250	1038	2830	-1792
Stavropol	4248	40	1033	3175	1765	+1410
North Osetia	35	-	5	30	420	-390
Chechen-Ingush	558	-	60	498	510	-12
Dagestan	1728	320	260	1148	605	+543
Karachai-Cherkess	180	100	-	80	285	-205
Kabardin-Balkar	17	-	-	17	385	-368
Kalmuk	163	-	-	163	190	-27
Grand Total	11353	500	2203	8650	10100	-1450

Note: Pavl = available (installed) power
Pidle = idle (unused) capacity
Pres = reserves
Pact.g = actual generation
Pload = loads
-/+ = deficiency or excess

It should be pointed out that the principal base case operating condition (Figure 2) corresponds to a zero power flow on interconnection ties between the North Caucasus and Transcaucasia. If by 2000 (the period under consideration) it becomes necessary to transmit power to Transcaucasia, the shortage may be even worse.

At present the shortage is covered by power transmitted from other parts of Russia mostly via Ukrainian networks. Commissioning of the Krasnodar Power Plant will make it possible to cut imports of power.

Table 2 lists operating conditions that were studied for the base case in both full-capacity and maintenance layouts (configurations). Figures 2 through 10 provide data characterizing these conditions for various configurations.

TABLE 2

Base Case Modes and Configurations

Mode No.	Configuration	Figure No.	N. Caucasus-Transcaucasia Power Flow
1-0-0	Full-capacity layout	2	0
1-1-0	Outage of Yuzhanaya-Rostov NPP line	3	0
1-2-0	Outage of Stavropol-Tsentralnaya line	4	0
1-0-1	Full-capacity layout	5	753
1-1-1	Outage of Yuzhanaya-Rostov NPP line	6	511
1-2-1	Outage of Tsentraln.-Zelenchuksk. line	7	500
1-3-0	Outage of ties to Ukraine	8	0
1-3-1	Outage of ties to Ukraine	9	212
1-4-0	Outage of ties to Ukraine and Yuzhnaya-RNPP line*	10	0

* Note: Operation possible only with a 1000 MW load shedding in the North Caucasus Interconnected Power System.

It can be inferred from the reported data that the base case layout assures sufficient stability and reliability margins for the principal operating mode meeting the n - 1 rule

The stability level starts dropping as soon as power is transmitted from the North Caucasus Interconnected Power System to Transcaucasia. The maximum allowable power flow for the full capacity layout is 750 MW (mode 1.0.1); however, with some lines disconnected, for example, the Stavropolskaya-Tsentralnaya or Tsentralnaya-Zelenchukskaya 500 kV line, the allowable power flow drops considerably to about 500 MW (modes 1.1.1 and 1.2.1), due to the current overload of the lines remaining in the weakened cut. This implies a degree of load shedding in Transcaucasia should these lines be tripped in mode 1.0.1.

Completion and commissioning of the 500 kV overhead line from the Yuzhnaya substation to the Rostov Nuclear Power Plant will permit the North Caucasus IPS to operate without the lines running across Ukraine (mode 1.3.0), with the allowable power flow to Transcaucasia within 210 MW (mode 1.3.1). However, the associated configuration, even without export to Transcaucasia, fails to satisfy the n -1 rule and will call for considerable load shedding (about 1000 MW) in case of emergency outages of the Yuzhnaya-Rostov NPP 500 kV line (mode 1.4.0).

5. STABILITY STUDY OF THE NORTH CAUCASUS IPS BASE CASE

The subject of the study was contingencies related to disconnection of the most loaded 500 kV lines because of a 0.12 s fault. Both the base case with no power flow to Transcaucasia and modes with interconnection ties between the IPS and Transcaucasia loaded to the limit were investigated.

In order to warrant stability in contingencies under the most strained modes, primarily for maintenance outage conditions, the North Caucasus IPS makes use of automatic emergency control facilities, which are basically oriented to unloading certain cuts of external and internal ties when they are weakened by an emergency or overloaded by emergency unbalance. The unloading is implemented by generation shedding and fast turbine tripping at large power plants or automatic load shedding.

At the phase under discussion the IPS will be equipped with an adaptive centralized automatic emergency control system, to be developed in the nearest future (see Section 5), which will permit coordination of emergency controllers.

Figures 11 through 15 show oscillograms which illustrate the contingencies revealed by the study. The oscillograms give the voltage at the junction of the faulted line and the phase angles of generators at the Stavropol Thermal Power Plant (North Caucasus IPS), the Inguri Hydraulic Power Plant (Transcaucasia), the Slavyanskaya Thermal Power Plant (Ukraine) with respect to generators of the Balakovskaya NPP (Volga IPS).

Principal stability problems of the base case configuration stem from the steady-state stability level of the ties remaining in operation after disconnection of faulted network components or generator units, rather than from severity of the initiating emergency disturbance, i.e. the kind and place of the fault. Therefore in accordance with the above-quoted results of mode calculations, transients associated with the principal calculation mode 1.0.0 are stable (see Figures 11 and 12).

Stability problems are aggravated in maintenance modes and with larger transits to Transcaucasian power systems. As will be apparent from Figure 13 the transient caused by disconnection of the faulted Stavropol-Tsentralnaya 500 kV line in mode 1.0.1 is stable. However, it is followed by a current overload of the lines in the emergency cut, which calls for a fast shedding of 250 to 300 MW in Transcaucasia.

The most grave stability problems are associated with open Ukrainian ties. Figure 14 shows the transient resulting from an emergency outage of the Yuzhnaya-Rostov NPP 500 kV overhead line. Stability of the transient in this contingency necessitates involvement of emergency control facilities to shed a large amount of loads. Shown in Figure 15 is the oscillogram of a transient whose stability is assured by shedding a total load of 1350 MW at the Krymskaya, Tsentralnaya, Nevinnomysskaya and Cherkeyskaya substations.

6. LOAD FLOW AND STABILITY STUDY OF THE NORTH CAUCASUS IPS AFTER COMMISSIONING THE KRASNODARSKY POWER PLANT

Two objectives of the study were as follows:

- assessment of adequacy of the planned transmission network development for the power output from the Krasnodarsky Power Plant to the IPS network in compliance with the mandatory requirements on the Krasnodarsky Power Plant's stability;

- assessment of the Krasnodarsky Power Plant's effects on stability of the IPS as a whole.

The block diagram of the Figure 1.2 was analyzed to make both above-mentioned assessments. It will be seen from the analysis results that this alternative meets mandatory requirements. Therefore the study did not consider further reinforcement of the network by an additional 500 kV line for the Krasnodarsky Power Plant's output within 900 MW; however, commissioning of a third unit will most probably necessitate construction of a 500 kV, 330 km long line to the Krymskaya substation.

Table 3 lists the modes considered for the project case. Figure 16 gives the principal calculation mode for the project case. This and further illustrations set off that part of the network layout which is associated with implementation of the power plant project.

The stability study of the Krasnodarsky Power Plant was carried out in compliance with regulatory documents. The steady-state stability margin was estimated for a 20% overload of the plant's generators above the rating for the full-capacity layout and for an 8% overload for configurations with each outgoing overhead line consecutively disconnected. The node loads were kept unchanged. The excessive power was compensated by generation shedding at the Inguri Hydro Power Plant, which corresponds to the worst mode-aggravating vector.

These modes (3.0.0 and 3.1.0 in Table 3 and Figures 17 and 18) were shown by the analysis to be allowable with respect to all the parameters checked.

TABLE 3

Project Case Modes and Configurations

Mode No.	Configuration	Figure No.	N. Caucasus-Transcaucasia Power Flow
2-0-0	Full-capacity layout	16	0
3-0-0	Full-capacity layout	17	0
3-1-0	Outage of Tsentraln.-Krasnodarsk. line	18	0
2-1-0	Outage of Yuzhnaya-Rostov NPP line	19	0
2-2-0	Outage of Tsentraln.-Krasnodarsk. line	20	0
2-0-1	Full-capacity layout	21	753
2-0-2	Full-capacity layout	22	1375
2-2-0	Outage of Tsentraln.-Krasnodarsk. line	23	753
2-2-1	Outage of Krasnodar-Zelenchuksk. line	24	500
2-3-0	Outage of ties to Ukraine	25	0
2-4-0	Outage of ties to Ukraine and Yuzhnaya-RNPP line*	26	0
2-3-1	Outage of ties to Ukraine	27	950

* Note: Operation possible only with a 190 MW load shedding in the North Caucasus Interconnected Power System.

Other modes shown in Table 3, with respective drawings, illustrate the effect of the Krasnodarsky Power Plant on operation of the North Caucasus IPS as a whole. No untoward consequences of the power plant commissioning were revealed by the analysis, meanwhile a number of positive effects became apparent. Specifically, the allowable power flow to Transcaucasia was found to increase from 750 MW to 1375 MW for the full-capacity layout (mode 2.0.2, Figure 22) and from 210 MW to 950 MW for the layout without the lines in Ukraine (mode 2.3.1, Figure 27). For the latter configuration and with the Yuzhnaya-Rostov NPP 500 kV line disconnected, the load shedding in the Interconnected Power System drops from 1000 MW to 190 MW.

Transient stability calculations were made for 0.12 s three-phase faults on 500 kV lines and for similar 0.2 s faults on 220 kV lines, followed by tripping of the line in question. Figures 28 through 40 give oscillograms of the associated transients.

In addition to items recorded for the base case study, these oscillograms show rotor angles of the Krasnodar SGPP generators connected to 500 kV and 220 kV buses. It follows from the oscillograms in Figs. 28 and 29 that for the full-capacity layout and the basic calculation mode of the IPS (no power flow to Transcaucasia), fault-generated transients on outgoing 500 kV and 220 kV overhead lines end in a stable transition to a new steady-state mode. The same stable are transients for maintenance configurations when a second 500 kV or 220 kV line gets tripped after a fault (see Figures 30 and 31).

Thus the proposed power output layout assures that all the mandatory requirements with respect to stability of the Krasnodar Power Plant are satisfied.

The stability analysis of the Interconnected Power System as a whole did not reveal any disturbances that would result in stability problems for the principal mode and the full-capacity layout. By way of illustration, Figures 32 and 33 show oscillograms of transients caused by trippings of the Yuzhnaya-Rostov NPP and Stavropol-Tsentralnaya 500 kV lines. Comparison of the transients caused by associated disturbances for the base and project cases in modes 1.0.0 and 2.0.0, respectively, shows them to be easier in the latter case.

Transients become more severe as the power flow to Transcaucasia increases. To cite an example, Figure 34 shows the transient caused by disconnection of the Stavropol-Tsentralnaya 500 kV line in mode 2.0.1 corresponding to the maximum allowable power flow to Transcaucasia for the base case. Again, the transient is less serious than that caused by a similar disturbance in the base case (compare to Figure 13) and does not necessitate a post-emergency shedding of the lines in the emergency cut.

Thus comparison of the stability levels of the base and project cases indicates that the Krasnodarsky Power Plant favorably affects the stability performance of the IPS as a whole. A particularly marked improvement is displayed with disturbances occurring on overhead lines north of the Krasnodarsky Power Plant. For example, while a tripping of the Yuzhnaya-Rostov NPP line in mode 1.3.0 of the base case without ties with Ukraine called for a total load shedding of over 1000 MW in the IPS, a similar disturbance for the project case (mode 2.3.0) does not necessitate automatic emergency control actions (Figure 35).

With large power flows to Transcaucasia, in both the base and project cases, disturbances on overhead lines south of the Krasnodar SGPP can result in post-emergency overloads of the affected lines making it necessary to carry out shedding in Transcaucasian power systems. Figure 36 shows an oscillogram of the mode 2.0.1 transient caused by an emergency outage of the Krasnodarskaya-Zelenchukskaya line. Even though the transient is stable, a 250-300 MW load shedding in Transcaucasia becomes necessary to prevent current overloads on overhead lines.

Given in Figures 37 through 39 are oscillograms of transients associated with an emergency outage of several 500 kV line in mode 2.0.2 distinguished by the maximum allowable project case power flow to Transcaucasia, which is much larger than the base case flow. The oscillograms put in evidence the fact that even under these extremely strained operating conditions an emergency outage of the Yuzhnaya-Rostov NPP or Stavropol-Tsentralnaya 500 kV line does not disturb stability of the IPS. However, disconnection of the Krasnodarskaya-Zelenchukskaya overhead line (Fig. 39) leads to out-of-step conditions between the North Caucasus and the Transcaucasia Interconnected Power Systems, which makes it necessary to shed a 150 MW load in

Transcaucasia by emergency control facilities (Fig. 40), to be followed by an additional 700 MW load shedding to eliminate post-emergency current overloads on 220 kV power transmission lines.

It has been demonstrated by the stability studies for the IPS as a whole that in none of the characteristic contingencies that have been examined the commissioning of the Krasnodarsky Power Plant impairs stability conditions, on the contrary, the operation of the power plant always contributes to a smoother course of events.

It does not in any way imply that a mere presence of the Krasnodarsky Power Plant makes it possible to abandon automatic emergency control facilities, which remain the only means for handling some contingencies, especially in maintenance configurations.

The centralized emergency control package, now under development, can adapt automatically to any layout and mode situations, which makes it unnecessary to study all specific contingencies for the IPS with the Krasnodar SGPP present. All that is required is to arrange additional information channels for monitoring the status and condition of new ties and the loading of the Krasnodarsky Power Plant itself.

7. FAULT ANALYSIS

The results of the fault analysis shown in Figure 41 are illustrated in the Table 4.

TABLE 4

Three-phase fault current at the Krasnodarsky Power Plant area

Bus	Fault Current, kA
# 339 - Krasnodarsky 500 kV	12.5
# 379 - Krasnodarsky 18 kV (from 500 kV)	263
# 381 - Krasnodarsky 18 kV (from 220 kV)	246
# 380 - Krasnodarsky 220 kV	25.0
# 321 - Tzentralnaya 500 kV	23.8
# 346 - Tzentralnaya 220 kV	27.7
# 337 - Kurgannaya 220 kV	17.8
# 9876 -Cheremushki 220 kV	10.4
# 8765 -Zilposelok 220 kV	16.9
# 333 - Zelenchukskaya 500 kV	10.3
# 347 - Armavir 220 kV	16.8

8. EMERGENCY CONTROL, DISPATCH, AND RELAY PROTECTION OF THE NORTH CAUCASUS IPS

8.1 Adaptive Centralized Emergency Control System

As described above, operation of the North Caucasus Interconnected Power System is characterized by considerable imports of power and energy from other power pools and can be influenced by power wheeling to the Transcaucasian power pool. The last-named factor, jointly with a general deficiency of power and energy in the North Caucasus IPS is the major obstacle in assuring stability of interconnected operation, on the one hand, and the principal source of uncertainty in planning its work, whether for a short or long term. The situation is further aggravated by an insufficient redundancy of 330 kV and 500 kV network, which makes its transfer capacity very sensitive to the maintenance outage of individual lines. Many maintenance configurations involving outage of 330 kV lines and especially 500 kV lines make it impossible to maintain stability, without use of the automatic emergency control system, when other overhead lines of the same voltage class are disconnected in emergencies. Depending on the pre-emergency operating conditions and the combination of lines in maintenance and emergency outage, different parts of the system can be affected necessitating different control actions with allowance for the status and condition of the entire power system.

At present, with virtually zero power flows to Transcaucasia and a considerable drop of its own loads, the North Caucasus Interconnected Power System does not face great difficulties in maintaining its stability. However, taking into account the potential growth of loads in the system and increasing transits, it is planned to commission in the North Caucasus IPS an adaptive centralized emergency control system (ACECS).

The principal mission of the ACECS is to automatically select and implement control actions taking full account of the emergency disturbance and the current status of the IPS.

The operating principle of the ACECS assuring implementation of the task is as follows.

The central computation unit of the ACECS uses on-line information on the configuration and the operating mode of the IPS to perform cyclically computations determining the emergency control actions to be taken to maintain stability should any of design contingencies occur. Control actions are selected from a set available for each particular instant and optimized with respect to a number of engineering and economic parameters. The control actions which are identified during each one to two minute long computation cycle are stored by the ACECS until the next cycle has been completed.

An emergency situation is recognized, and the respective preselected set of control actions implemented, within 0.2-0.3 s after a contingency has occurred.

The efficiency function of the principal ACECS algorithm is to minimize control actions by several criteria assuring a simple stable transition to the post-emergency operation with an 8% margin of post-emergency steady-state stability, with a slight extra margin allowing primarily for a time lag in entering the preselected control actions.

The ACECS cannot handle a limited range of specific stability problems related to compensation of fast transients, which are associated with heavy faults close to the bus of individual power plants and occur generally in maintenance configurations. Essentially the solution of the problems boils down to preventing the running-out of the generator about the rest of the system at an initial phase of the transient and can be obtained by unsophisticated local tools. For power units of a thermal plant it can be a standard electrohydraulic converter in the turbine control system, impulse shedding devices and power limiters.

Information on new elements in the IPS layout must be loaded into the simulator which is stored in the central computation unit of the ACECS; additional communication channels must be also provided; in the specific case of the Krasnodarsky Power Plant there must be channels of on-line information on the open/closed state, the active power and the voltage on both ends of all new lines commissioned together with the power plant. Actuators are standard emergency disconnection transducers of overhead lines and generation units. No revisions are necessary in the algorithm or software of the ACECS because this system has a built-in capacity to adapt to any changes in the power system configuration.

Because power units of a steam-gas power plant differ from those of conventional condensation plants impulse shedding devices and power limiters of the Krasnodar Power Plant will most probably have to be modified. As a last resort, if it proves impossible to use electrohydraulic converters, coarser generation shedding devices will have to be installed.

Automatic emergency control facilities, which are intended to handle such problems as elimination of out-of-step conditions, frequency unloading of power units etc., will be selected according to standard procedures and are considered at the present stage.

8.2 Dispatch

The existing pattern of dispatching control will be preserved after commissioning of the new Krasnodarsky Power Plant and new 500 kV power transmission lines from the Center ISP to the North Caucasus ISP: the operator at the Central Dispatch Office (CDO) of Russia's Unified Power System will supervise only the power flow to the North Caucasus ISP to be within the daily schedule set by the CDO on the basis of proposals by the North Caucasus IPS, and maintenance outages of interconnection 500 kV tie lines.

All other IPS operation control functions and regulation of power flows from the Center IPS and Ukraine in accordance with the schedule will by done by the dispatcher at the North Caucasus Interconnected Dispatch Center in Pyatigorsk.

Dispatching control of the new facilities, viz. the Krasnodarsky Power Plant and the Rostov 500 kV substation, will necessitate new telemechanic and telephone communication channels from the facilities to the dispatching centers of the Kuban and Rostov utilities, respectively. The necessary data on their status will be transmitted further with the help of available communication channels between dispatching centers of the respective power systems to the North Caucasus Interconnected Dispatch Center.

Because of a high manoeuvrability of steam-and-gas units, the Krasnodarsky Power Plant can be covered by the existing frequency and power control system of the North Caucasus IPS which implements the secondary control maintaining automatically the scheduled power flow of the Interconnected Power System using frequency correction.

Another vital function of this automatic control system is to prevent overloads of power transmission lines by redistributing generation among power plants of the North Caucasus IPS. The commands to change automatically the output of the Krasnodarsky Power Plant must come from the central computer of this automatic control system at the ISP Dispatch Center by a fast and reliable channel.

8.3 Relay Protection

Relay protection systems of all new 500 kV lines will use solid-state microelectronic components.

The main protection tool for overhead lines will be the high-frequency filter directional comparison protection system with a three-phase power direction sensor (of PDE-2003 type in Russia).

The back-up protection against phase-to-phase faults will be assured by the three-stage distance protection system (of PDE-2001 type in Russia). The back-up protection against ground faults will be assured by the four-stage zero-sequence protection system (of PDE-2002 type in Russia). Fast response of the second stage of the PDE-2001 distance protection system is provided when the PDE-2001 at the opposite end of a overhead line is triggered to trip three phases.

The protection package of 500 kV lines also comprises the breaker back-up device featuring immediate transmission of an additional signal to open the failed circuit breaker of PDE-2005 type in Russia); only after a repeated failure the breaker back-up device opens all breakers involved in feeding the fault site.

Standard protection packages for 220 kV lines are similar to their 500 kV counterparts, although less sophisticated.

Russian-made protection packages of high-power generators are similar in design and performance to those used elsewhere in the world.

Main protections are longitudinal and transversa differential protection and ground fault protection in the armature winding and the excitation system. The back-up protections will handle external symmetrical and asymmetrical short-circuits, rotor and armature winding overloads, out-of-step operation with or without loss of excitation.

The relay protection packages of transformers and autotransformers assure main longitudinal differential and gas protection, as well as protection against partial breakdown of 500 kV bushing insulation. The back-up protections will include the overcurrent protection or distance protection against external phase-to-phase faults, as well as current or directional current protection against external single-phase short-circuits.

500 kV lines will be equipped with reclosure packages and automatic voltage rise controllers (of PDE-2004 type in Russia). The reclosing device is actuated by the main protection and fast back-up protection stage.

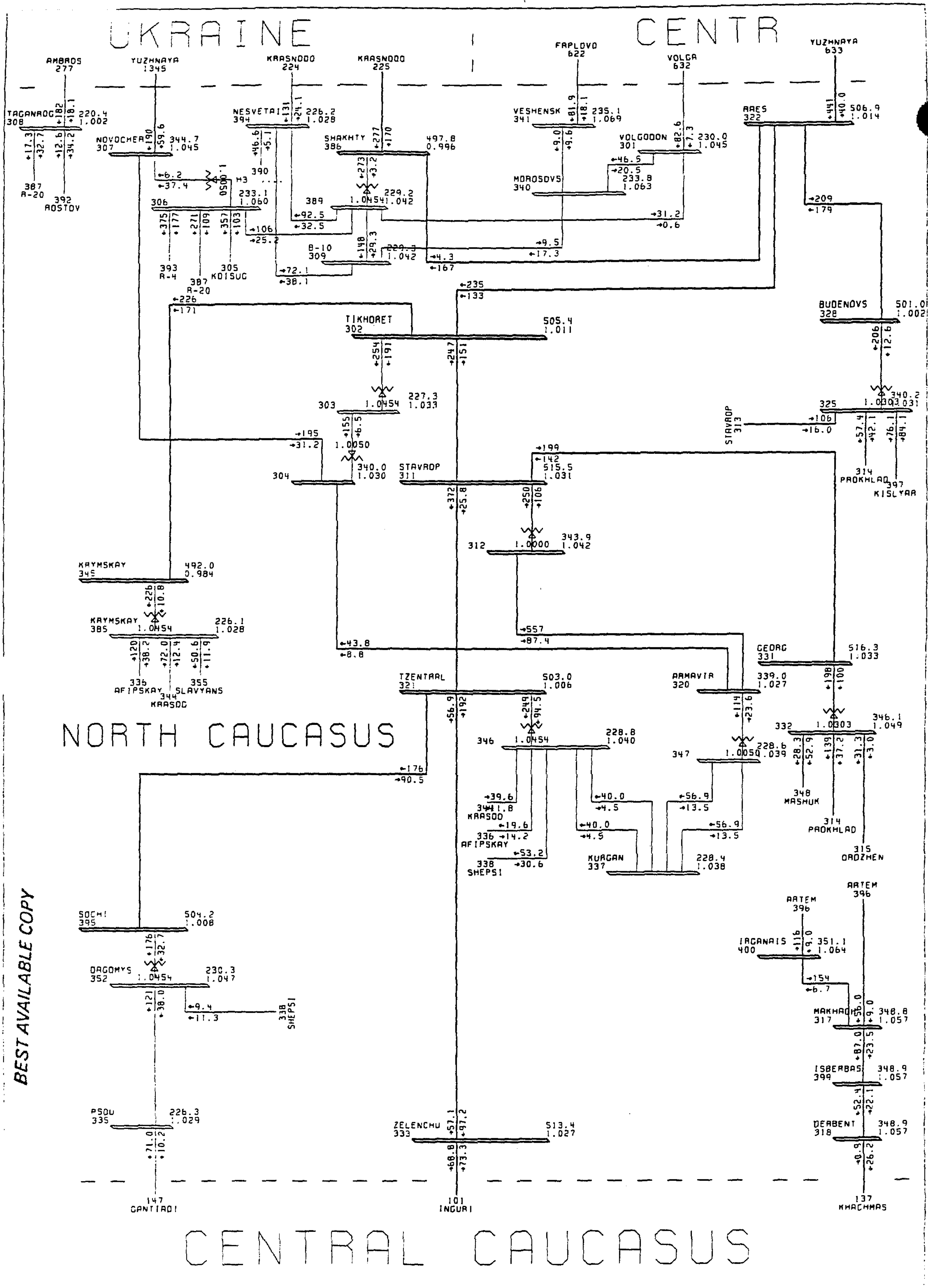
Starting and selection controls of the PDE-2004 determine the actions to be taken in accordance with the fault. In case of single-phase fault a command is transmitted to open the located faulted phase and to reclose it after a specified dead time; if the fault is not cleared, all three phases of the line are opened. In case of a phase-to-phase fault all three phases are opened immediately and then reclosed kind of

Automatic voltage rise controllers are mounted on 500 kV lines over 100-150 km long whose reactive power generated because of one-end opening may result in a voltage rise which is hazardous for the equipment at the open end and for the buses of the substation keeping the line energized.

Starting elements of the automatic voltage rise controlllers respond to an increase of the phase voltage and have two actuation stages of different sensitivity.

The finer stage of the controller is actuated by the voltage starting element, with the var fed by the line above the setting, and sends, after the first time lag, a command to start shunt reactors of this end of the line, if available, and those at the other end; after a second time lag the controller deenergizes the line forbidding reclosures.

The coarse stage of the controller is actuated by the voltage starting element, with the var fed by the line above the setting, and sends a command to deenergize the line at the given substation forbidding reclosures and uses telecommunication channels to trip the line at the opposite end also forbidding reclosures.



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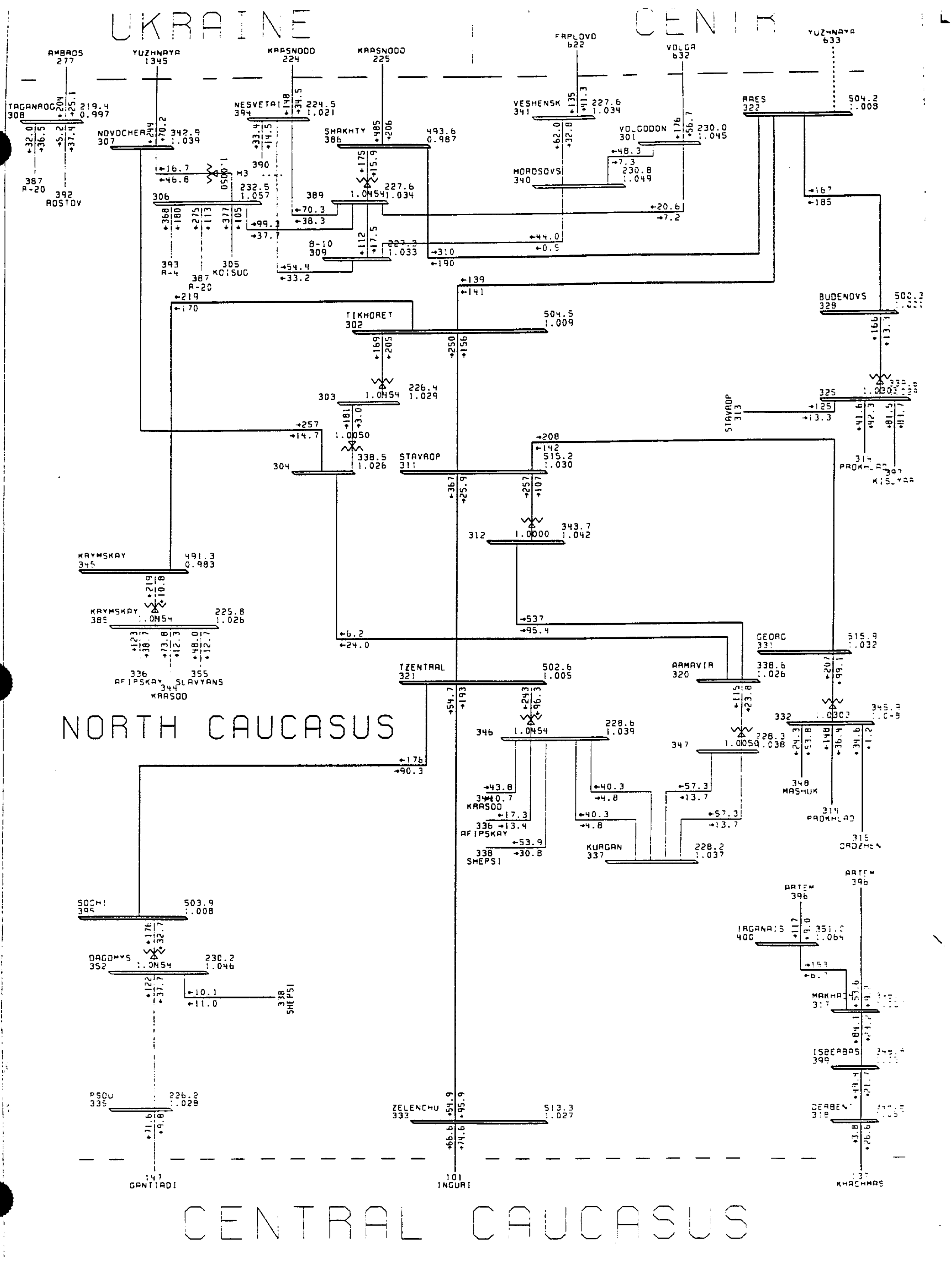
MOSTOVSKAYA PROJECT, BASE CASE (1-0-0)

FIG. 2 MON, SEP 27 1965 09:54

0.950UV 1.120UV



MOSTOVSKAYA PROJECT, BASE CASE (1-1-0)

FIG. 3 MON, SEP 27 1965 10:12

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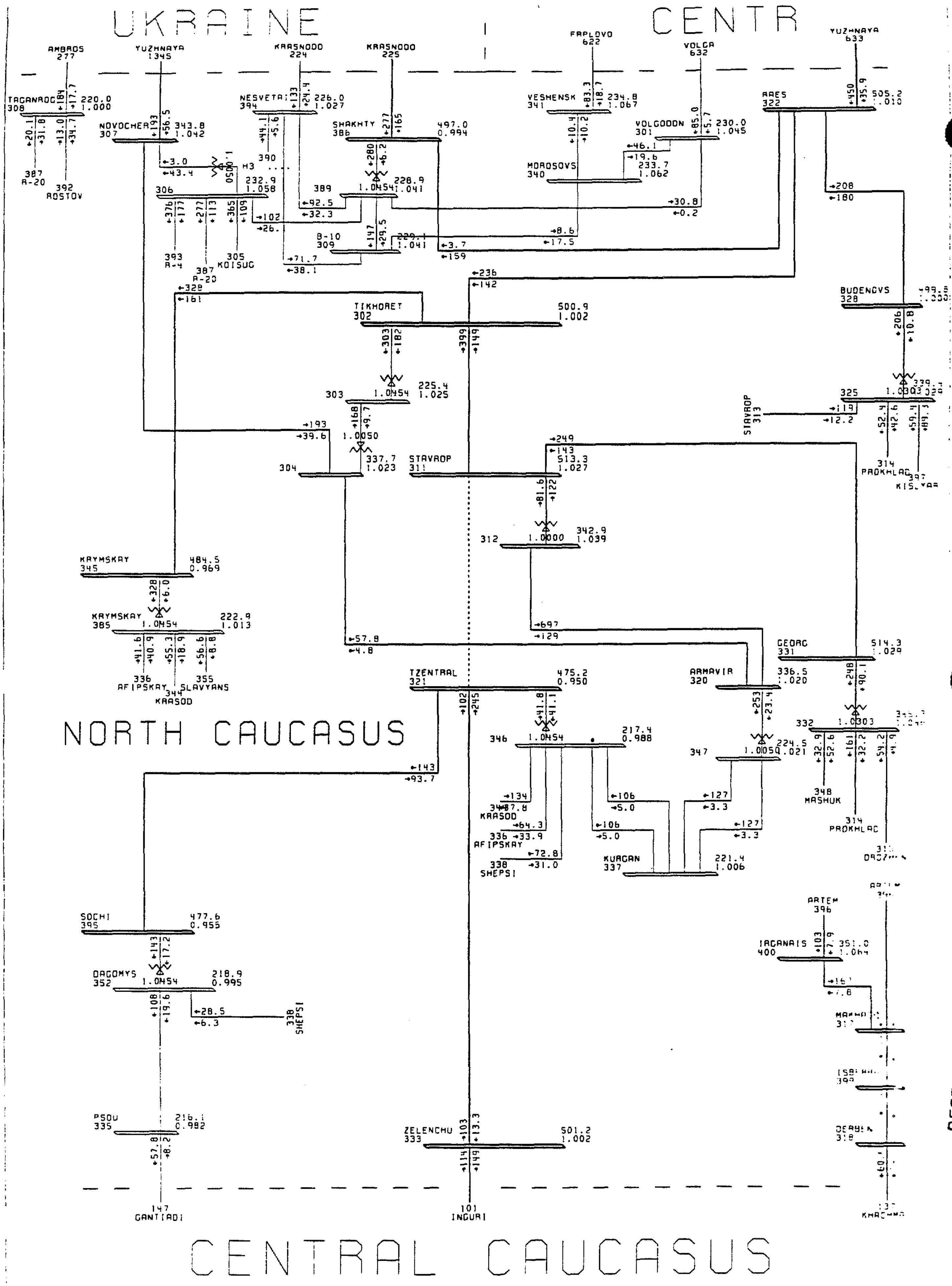
90 % BASE
0.950 UV 1.120 OV
KV: ≤220 ≤330 ≤500

549



MOSTOVSKAYA PROJECT, BASE CASE (1-2-0)

FIG. 4 MON, SEP 27 1965 10:17

90 % RATED
0.950UV 1.050UV
KV: ≤220 , ≤330 , ≤500

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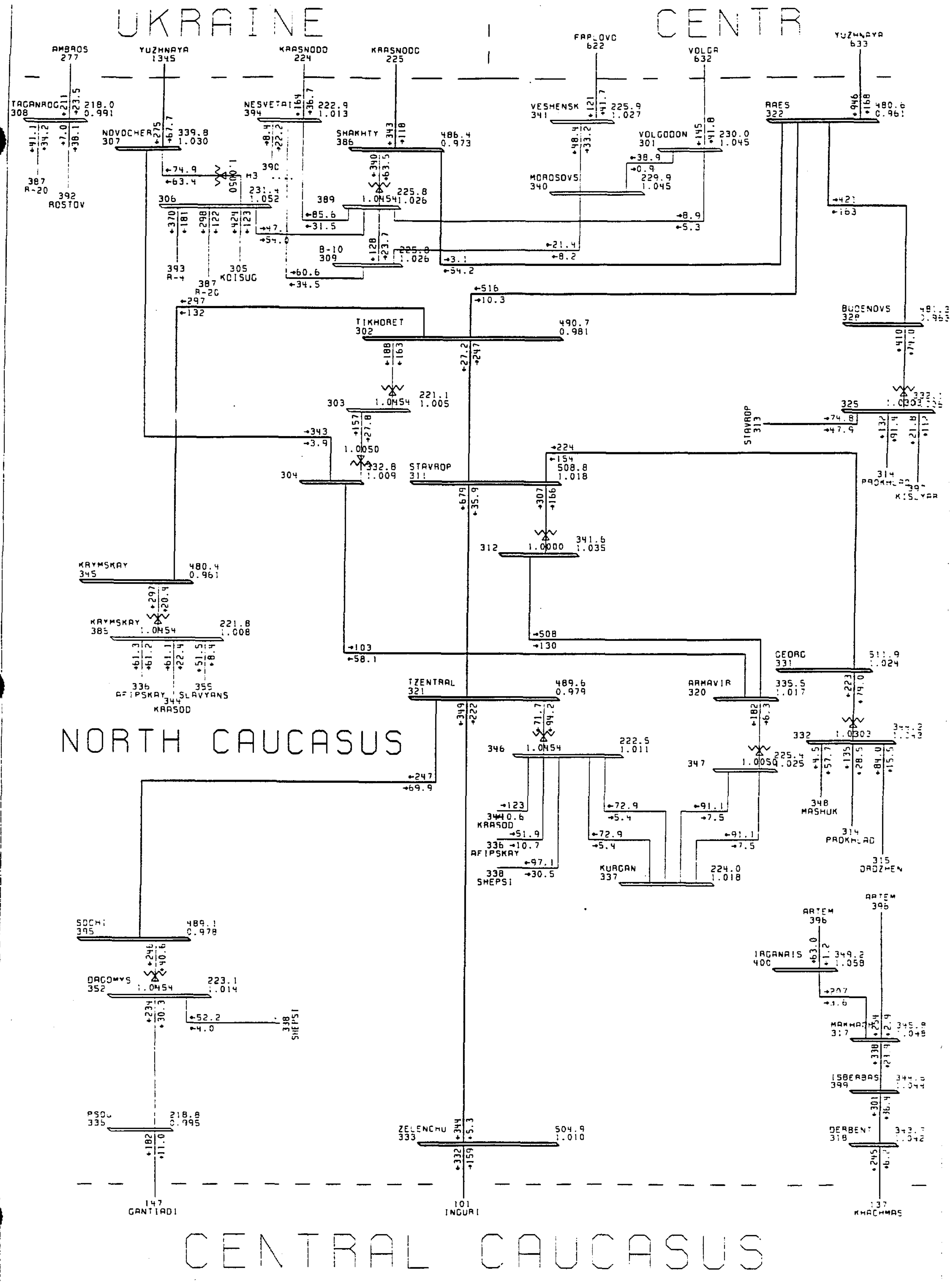
548



MOSTOVSKAYA PROJECT, BASE CASE (1-0-1)

FIG. 5 MON, SEP 27 1995 10:20

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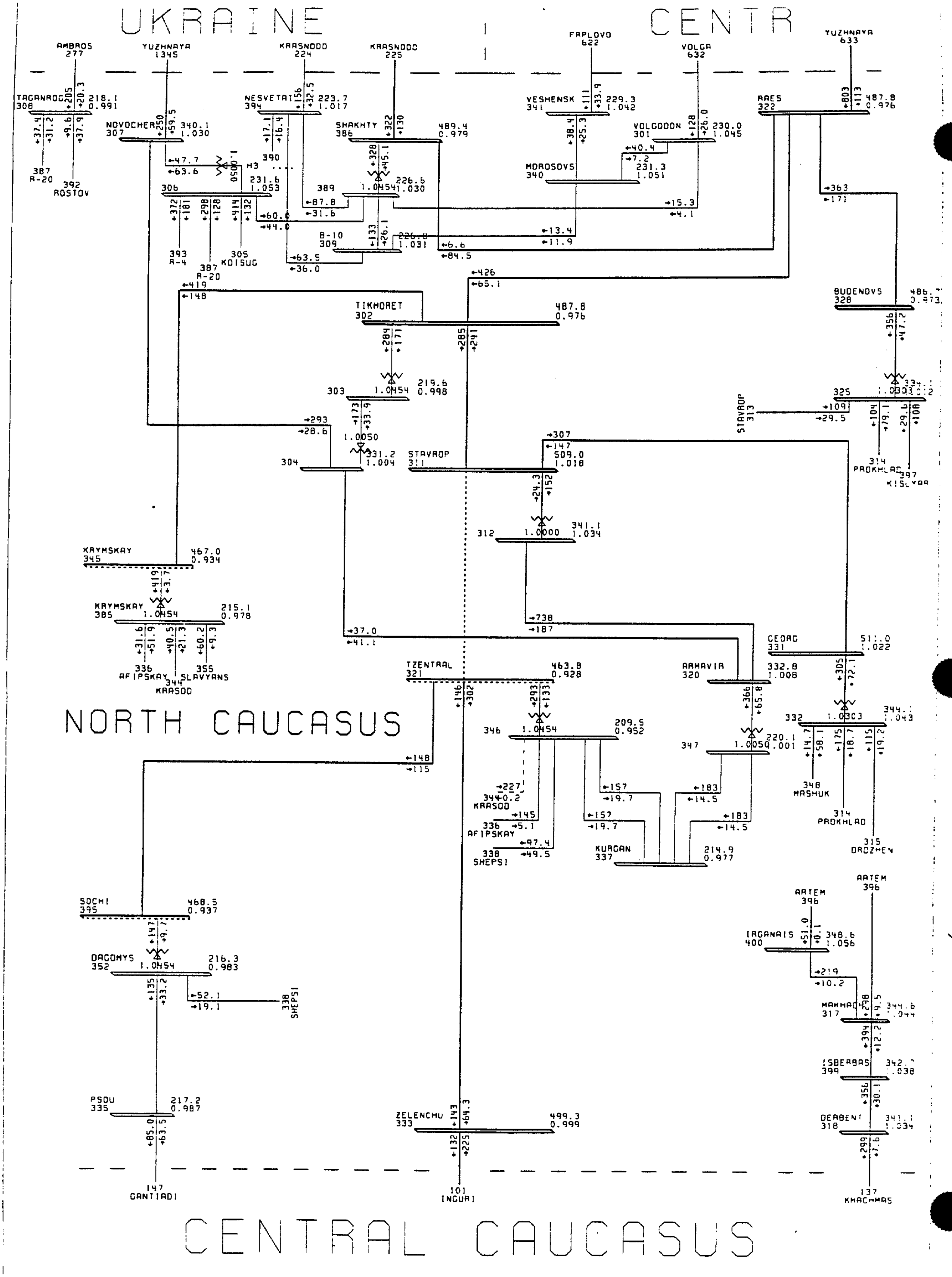
90 % RATEA
0.950UV 1.120UV
KV: ≤220 ,≤330 ,≤500

POWER TECHNOLOGIES, INC.

549

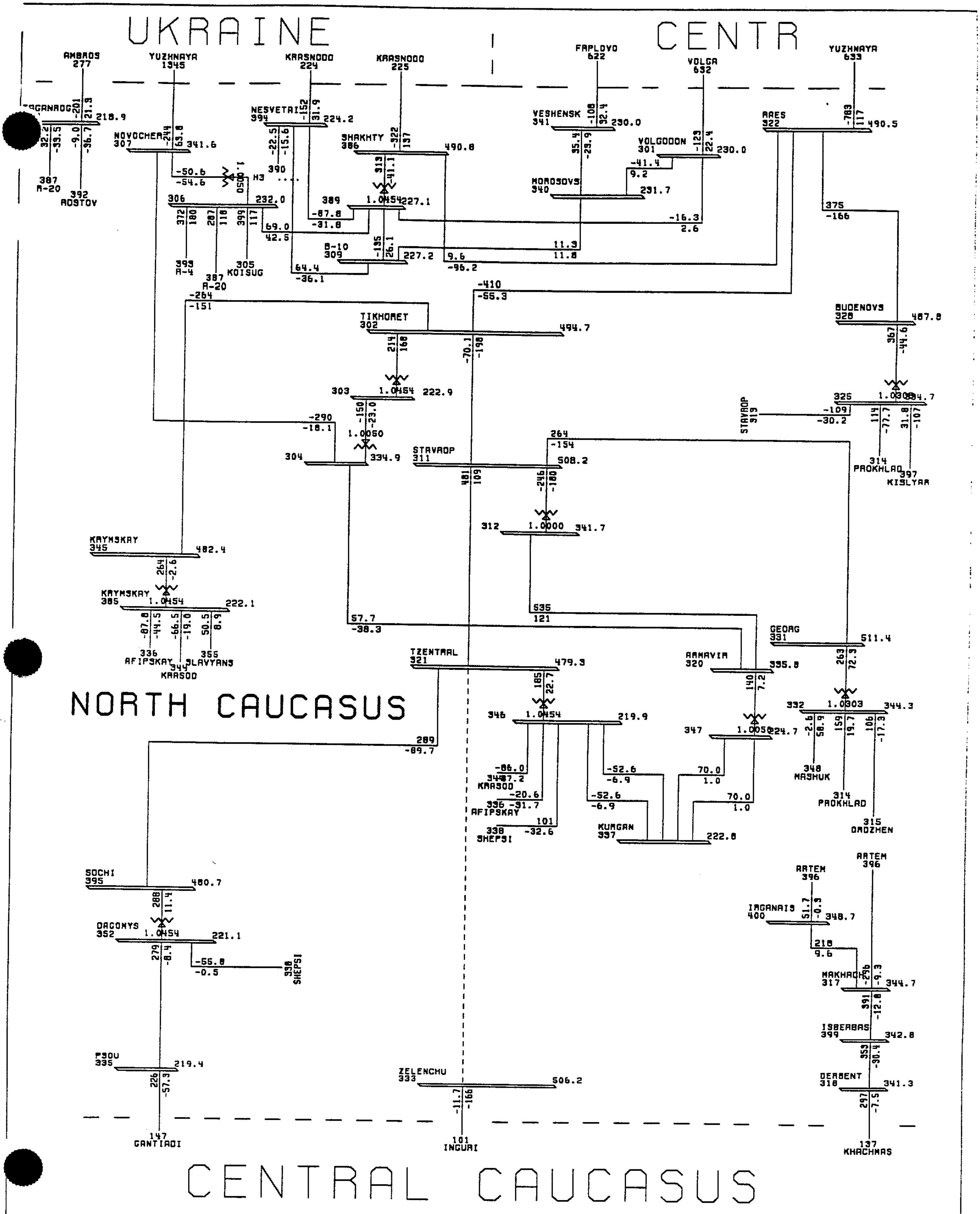


MOSTOVSKAYA PROJECT, BASE CASE (1-1-1)

FIG. 6 MON, SEP 27 1965 10:32

90 % RATEA
0.950UV
Kv: ≤220 , ≤330 , ≤500

550



MOSTOVSKAYA PROJECT, BASE CASE (1-2-1)
LINE TZENTRAL-ZELENCHUK OUT
FIG. 7 THU OCT 05, 1995 10:31

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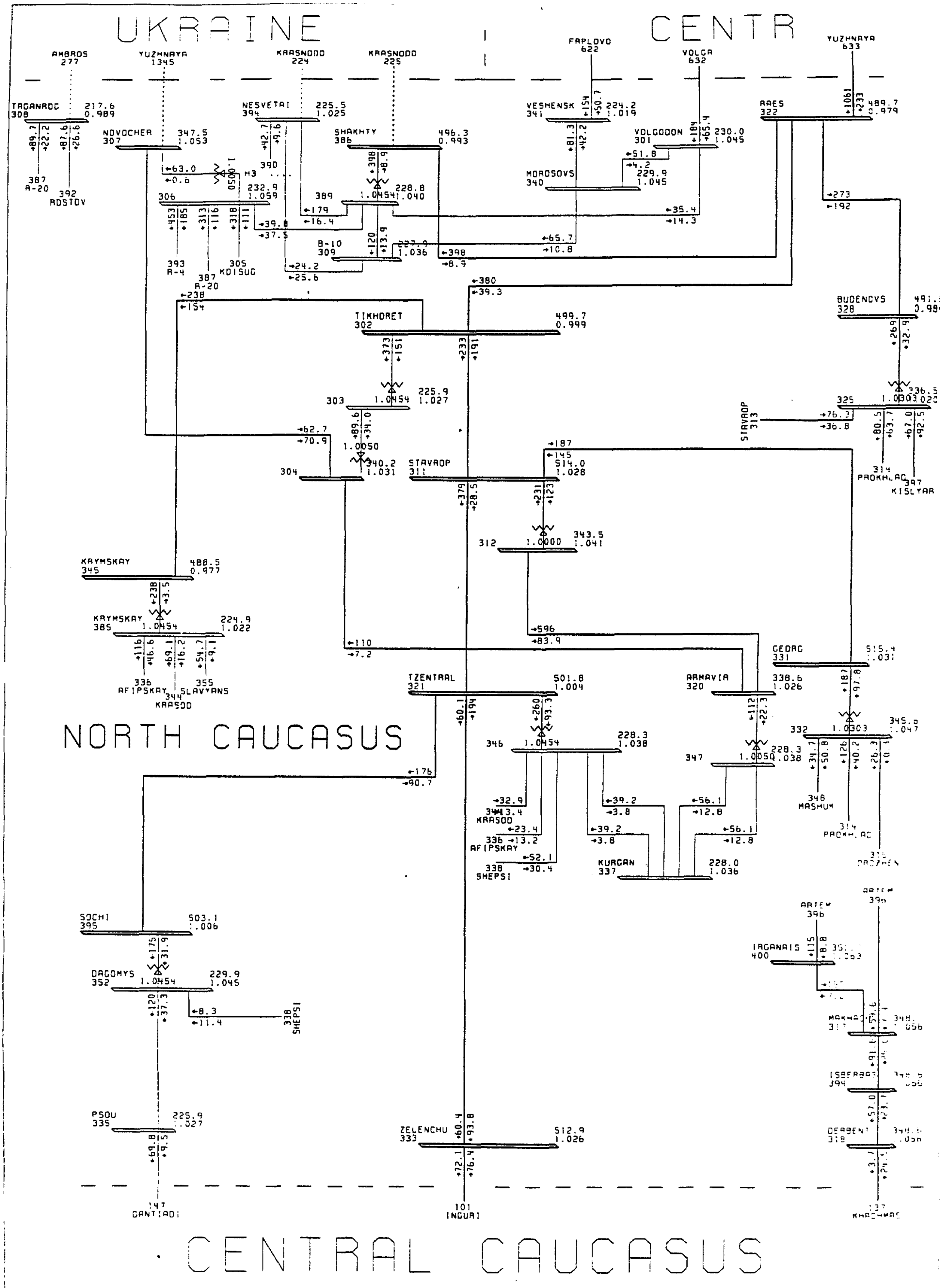


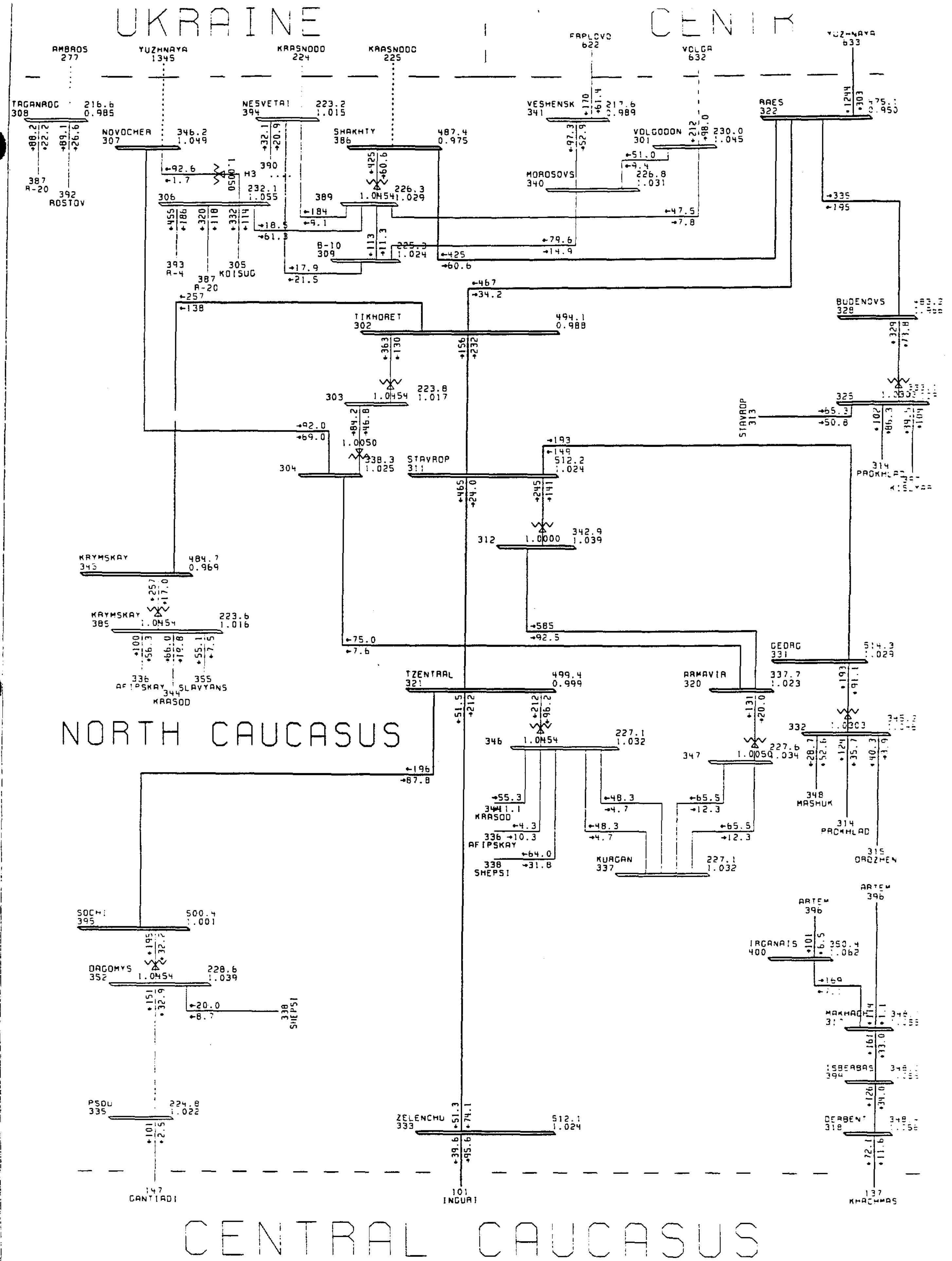
MOSTOVSKAYA PROJECT, BASE CASE (1-3-0)

FIG. 8 MON, SEP 27 1965 10:28

90 % RATES
0.950UV 1.120OV
KV: ≤220 . ≤330 . ≤500

POWER TECHNOLOGIES, INC.

552



MOSTOVSKAYA PROJECT, BASE CASE (1-3-1)

FIG. 9 MON, SEP 27 1965 10:34

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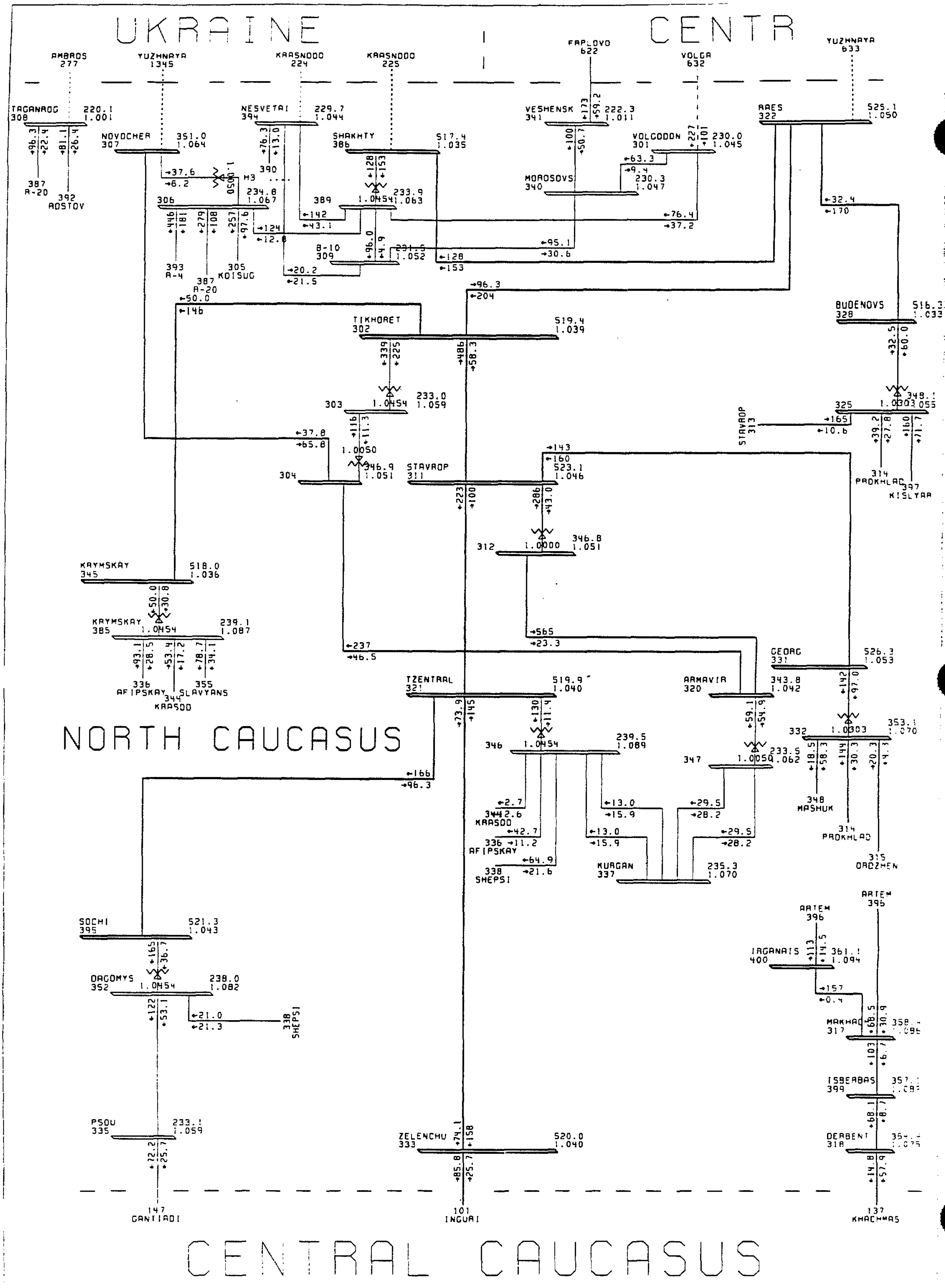
90 % RATER
KV: ≤220 , ≤330 , ≤500

553



MOSTOVSKAYA PROJECT, BASE CASE (1-4-0)

FIG. 10 MON, SEP 27 1993 10:45

90 % RATEA
0.950UV 1.120OV
KV: ≤220 , ≤330 , ≤500

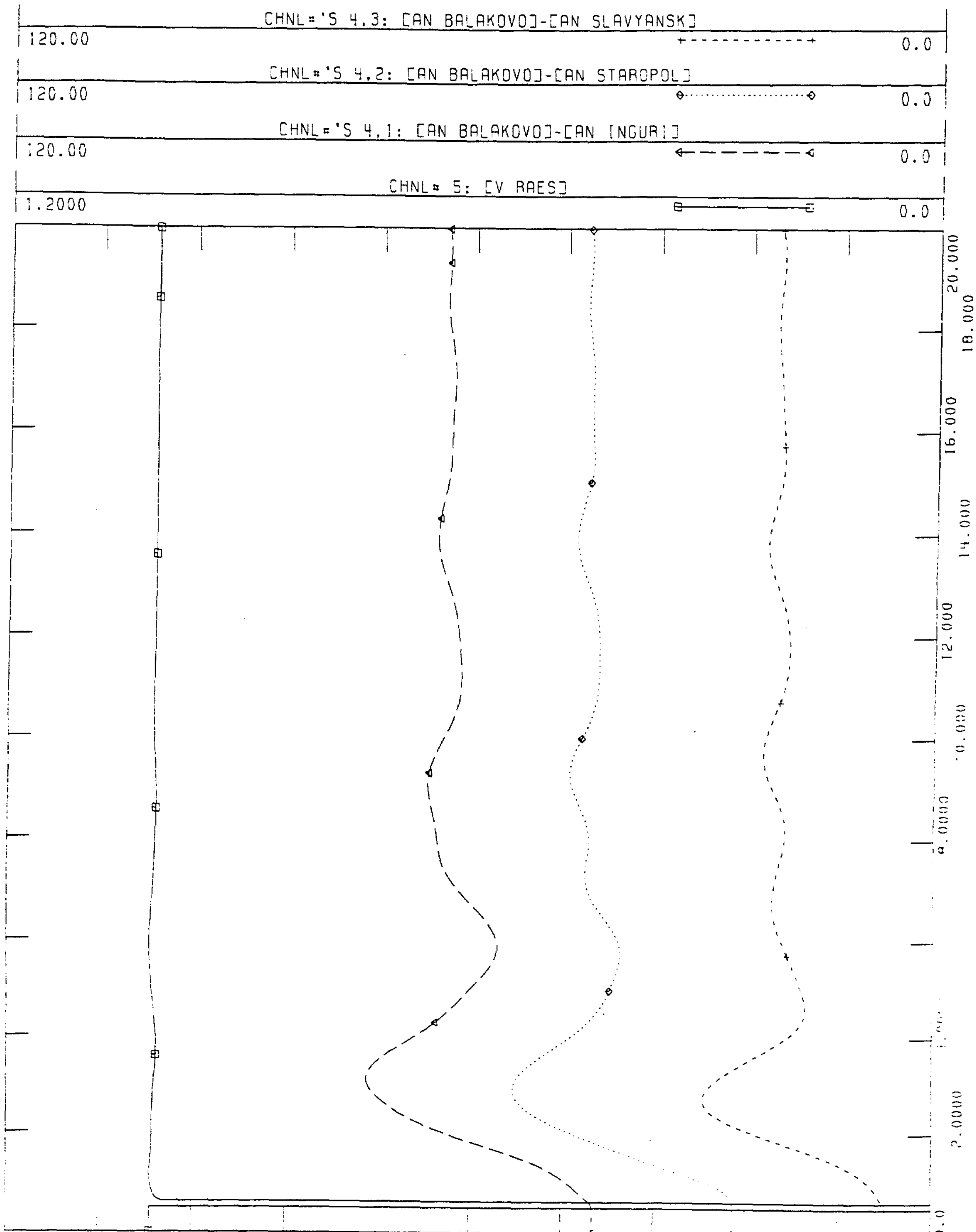
554

MOSTOVSKAYA PROJECT, BASE CASE (1-0-0)
3-PHASE FAULT RAES, LINE RAES-YUZNAYA OUT

FILE: A:\PLOT\PL11

THU, SEP 28 1995 15:15

FIG. 11



555

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MOSTOVSKAYA PROJECT, BASE CASE (1-0-0)
3-PHASE FAULT STAVROPOL, LINE STAVROPOL-TZENTRAL OUT

POWER TECHNOLOGIES, INC.

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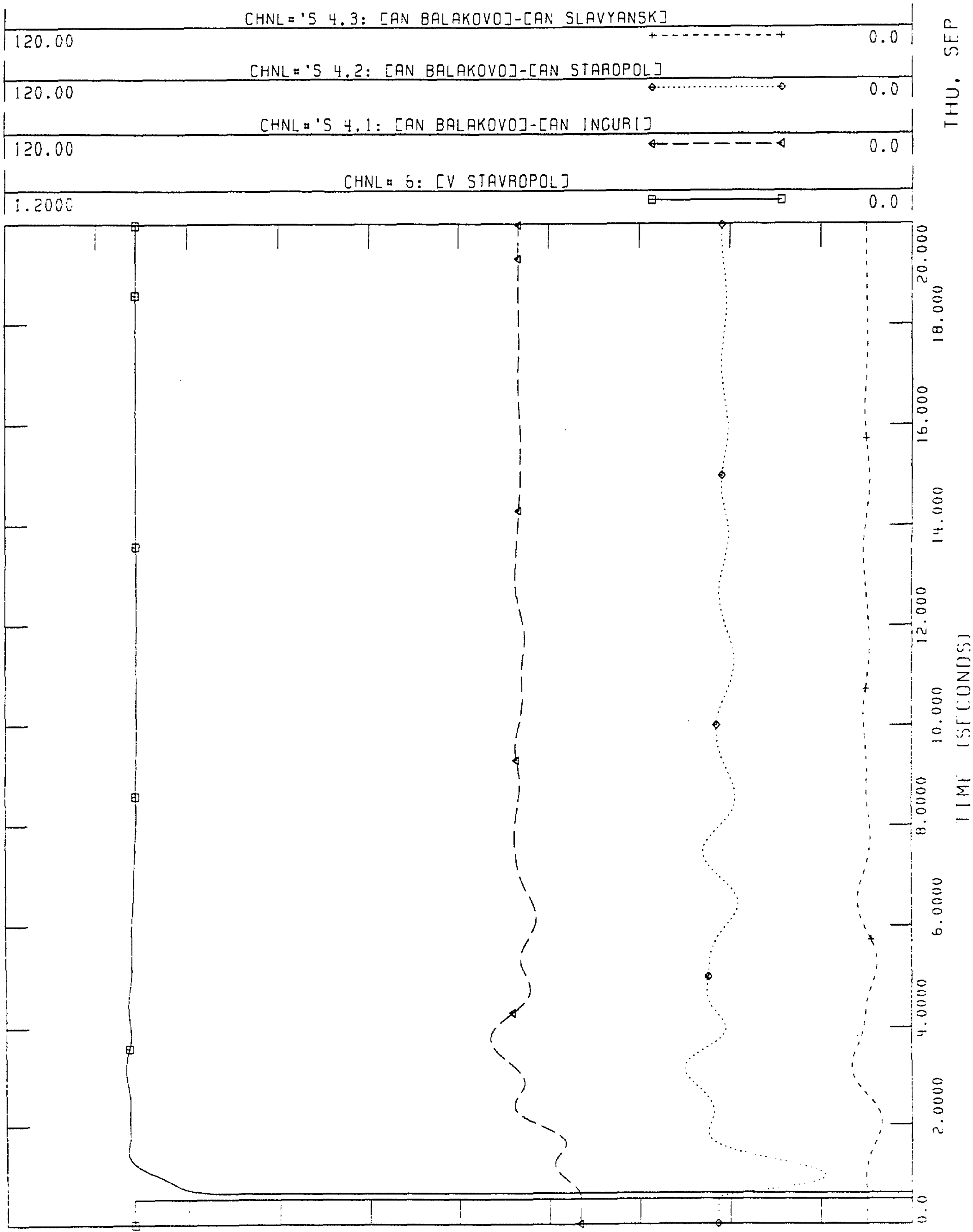
THU, SEP 28 1995 15:17

FIG. 12



556

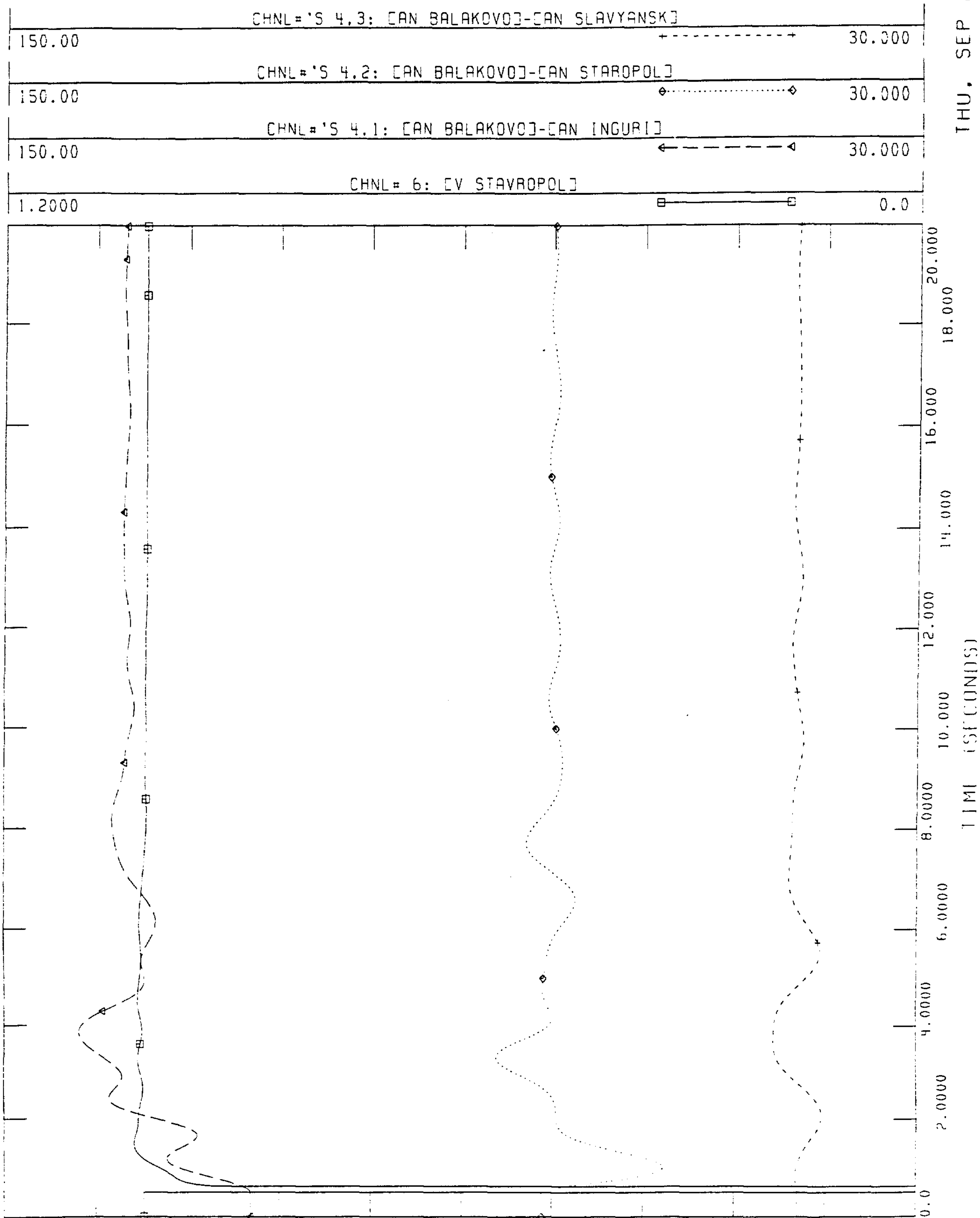
POWER TECHNOLOGIES, INC.

MOSTOVSKAYA PROJECT, BASE CASE (1-0-1)
3-PHASE FAULT STAVROPOL, LINE STAVROPOL-TZENTRAL OUT

FILE: A:\PLOT\PL13

THU, SEP 28 1995 15:18

FIG. 13



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551

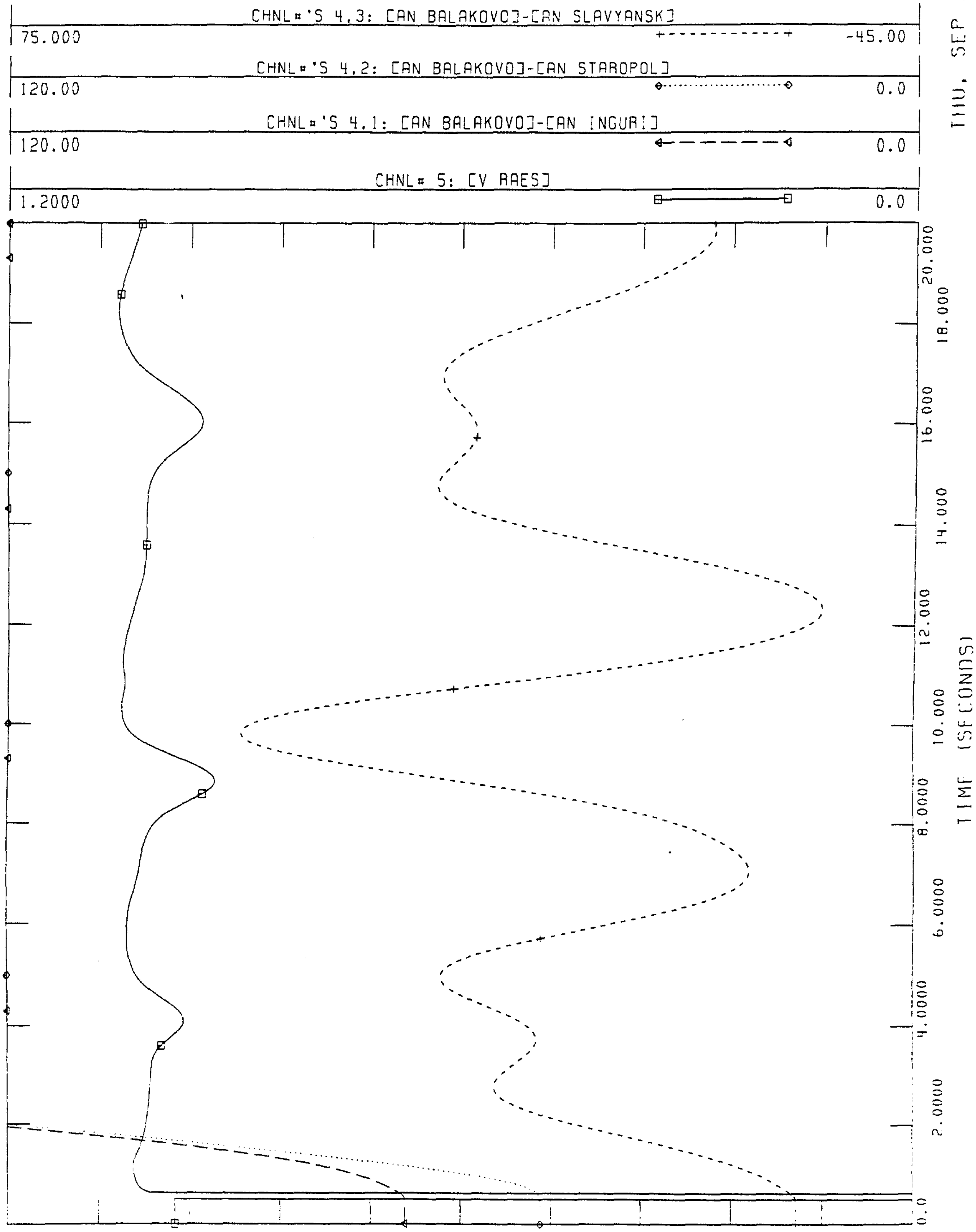
MOSTOVSKAYA PROJECT, BASE CASE (1-3-0)
3-PHASE FAULT RAES, LINE RAES-YUZNAYA OUT

POWER TECHNOLOGIES, INC.

FILE: A:\PLOT\PL14

THU, SEP 28 1995 15:19

FIG. 14



558

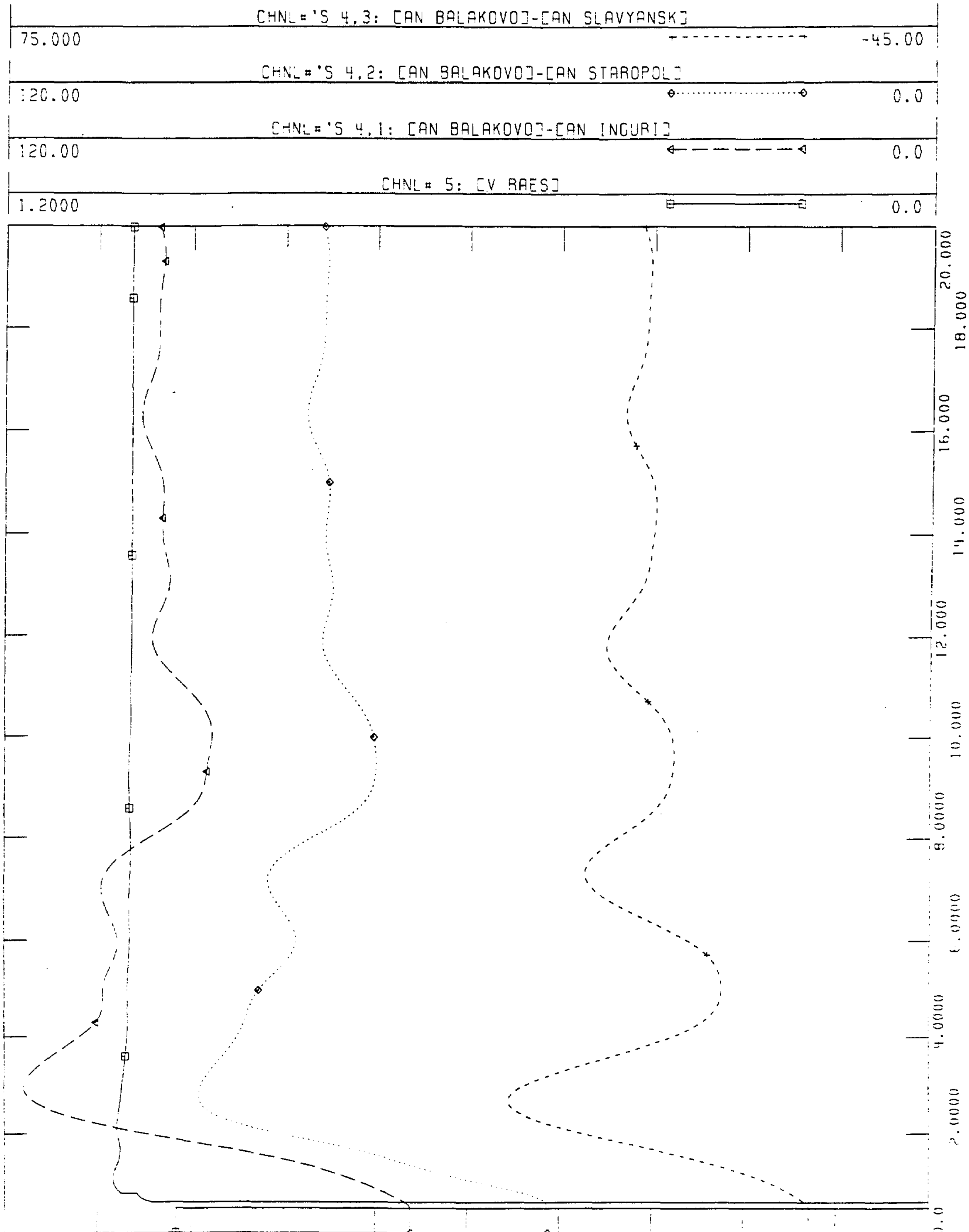
POWER TECHNOLOGIES, INC.

MOSTOVSKAYA PROJECT, BASE CASE (1-3-0)
3-PHASE FAULT RAES, LINE RAES-YUZNAYA OUT

FILE: A:\PLOT\PL15

THU, SEP 28 1995 15:20

FIG. 15



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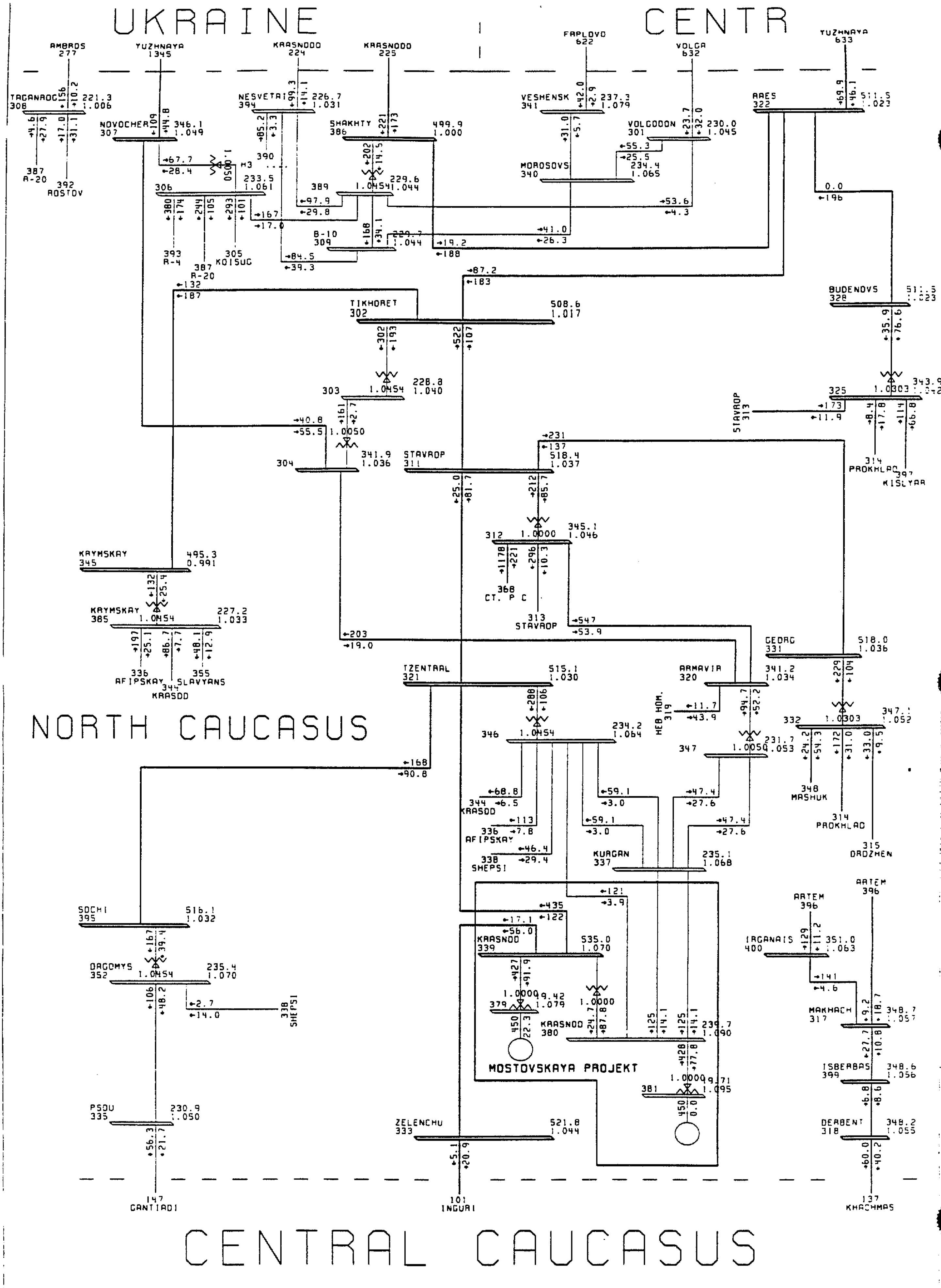
569

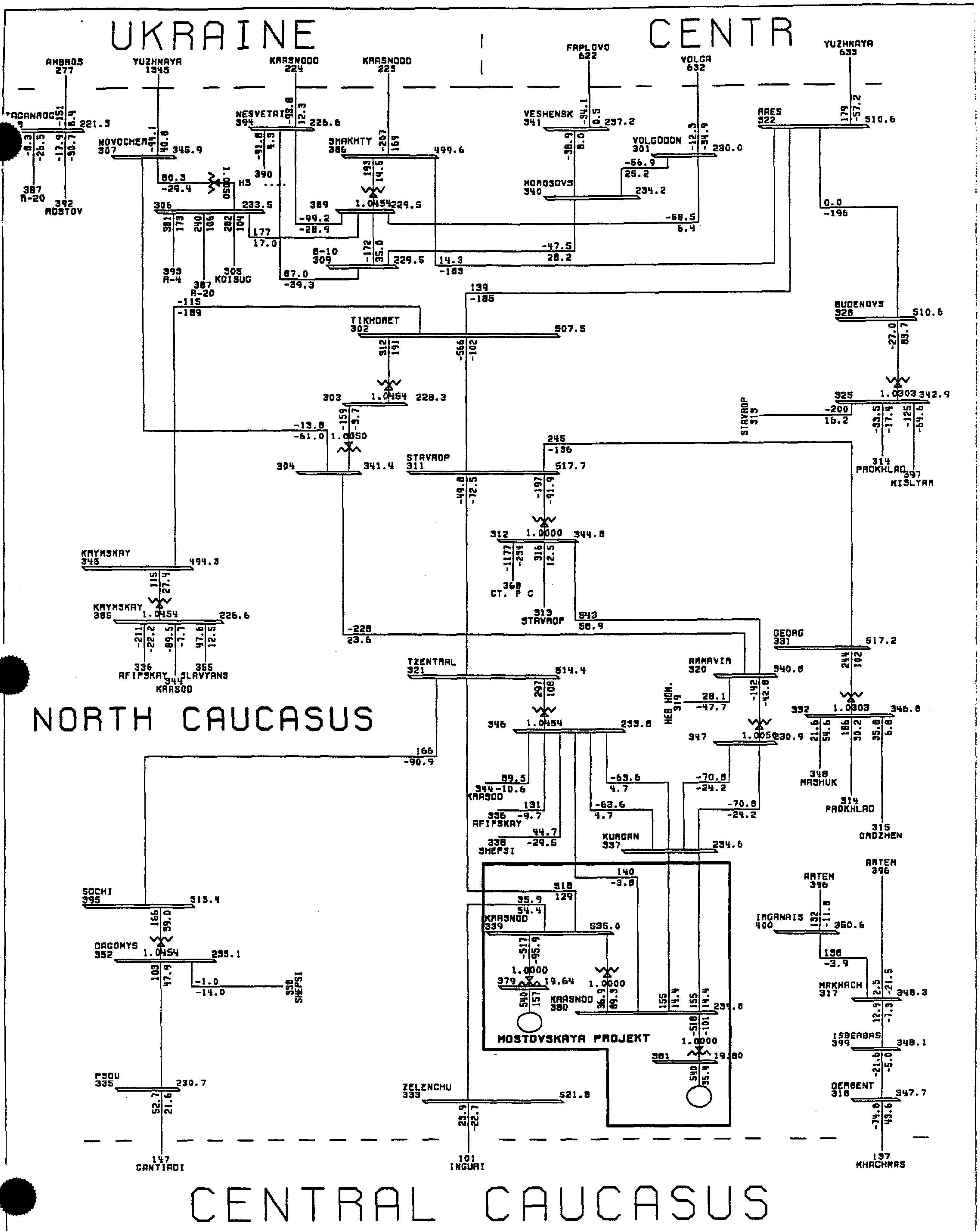


MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-0)

POWER TECHNOLOGIES, INC. FIG. 16 MON, SEP 27 1965 10:55

90 % RATEA
0.950UV 1.120OV
KV: ≤220 .≤330 .≤500

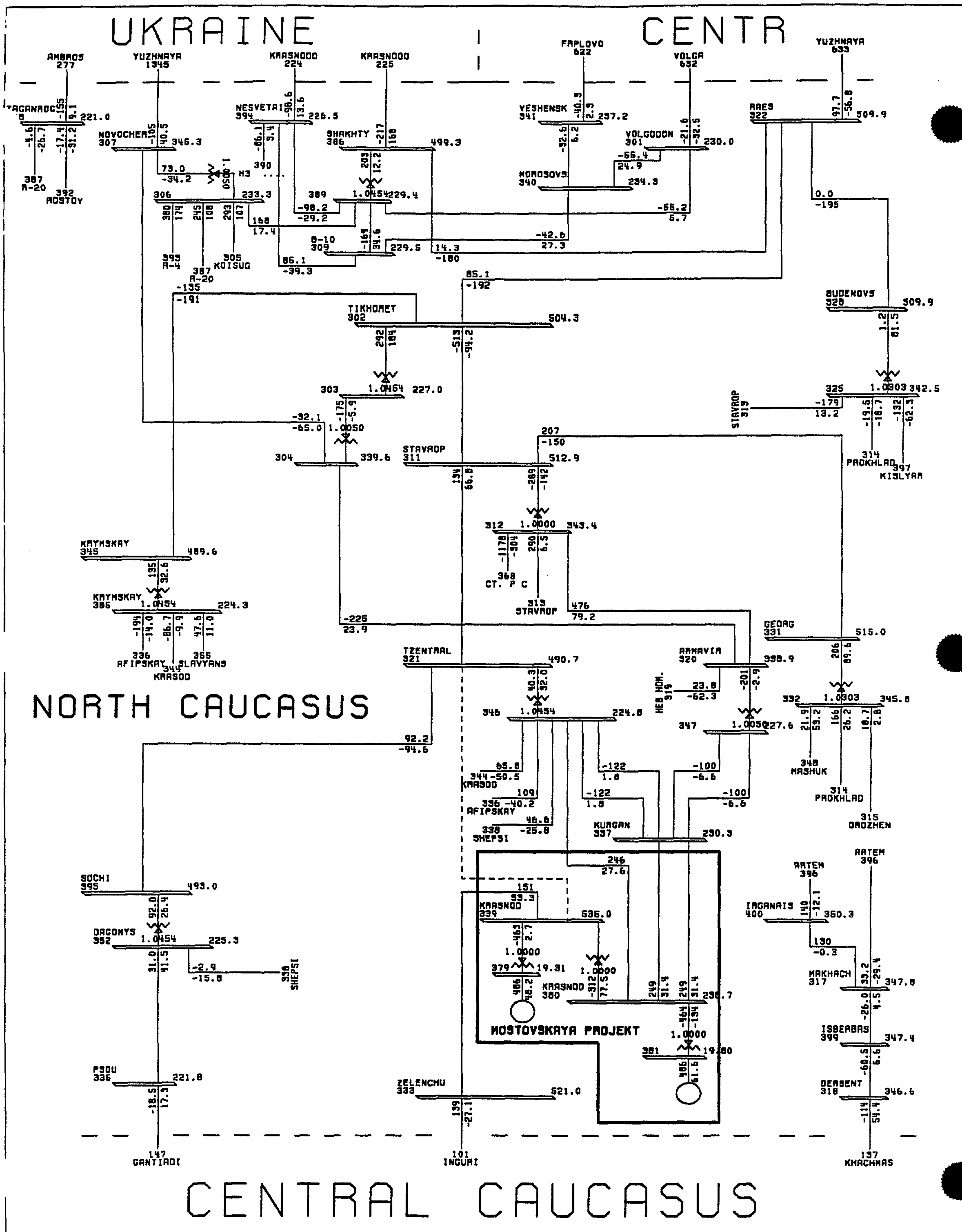
563



MOSTOVSKAYA PROJECT, PROJECT CASE (3-0-0)

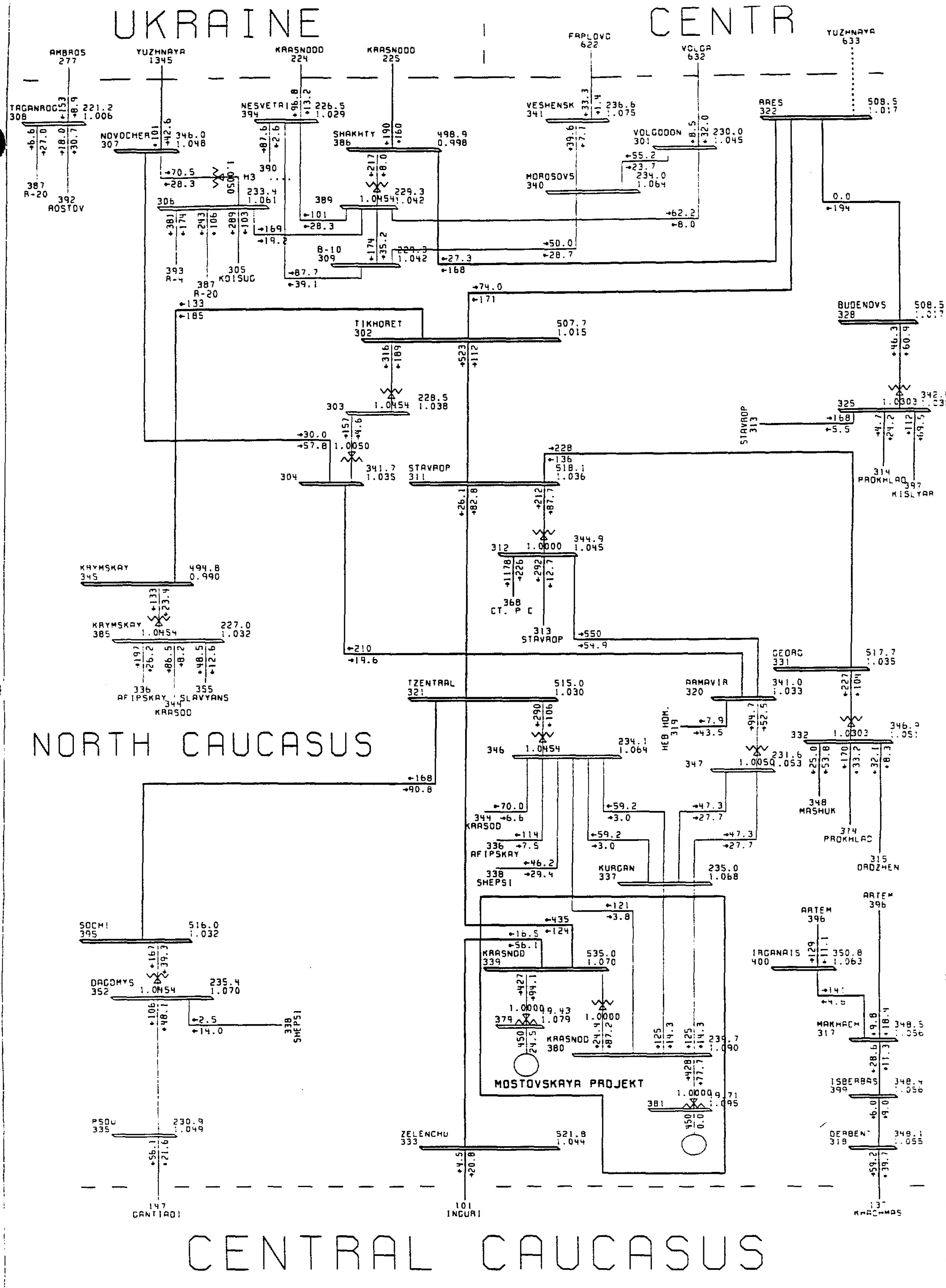
POWER TECHNOLOGIES, INC.® FIG. 17 FRI OCT 06, 1995 14:13

56



POWER TECHNOLOGIES, INC.

MOSTOVSKAYA PROJECT, PROJECT CASE (3-1-0)
LINE TZENTRAL-KRASNODAR-ZELENCHUC OUT
FIG. 18 FRI OCT 06, 1995 14:21

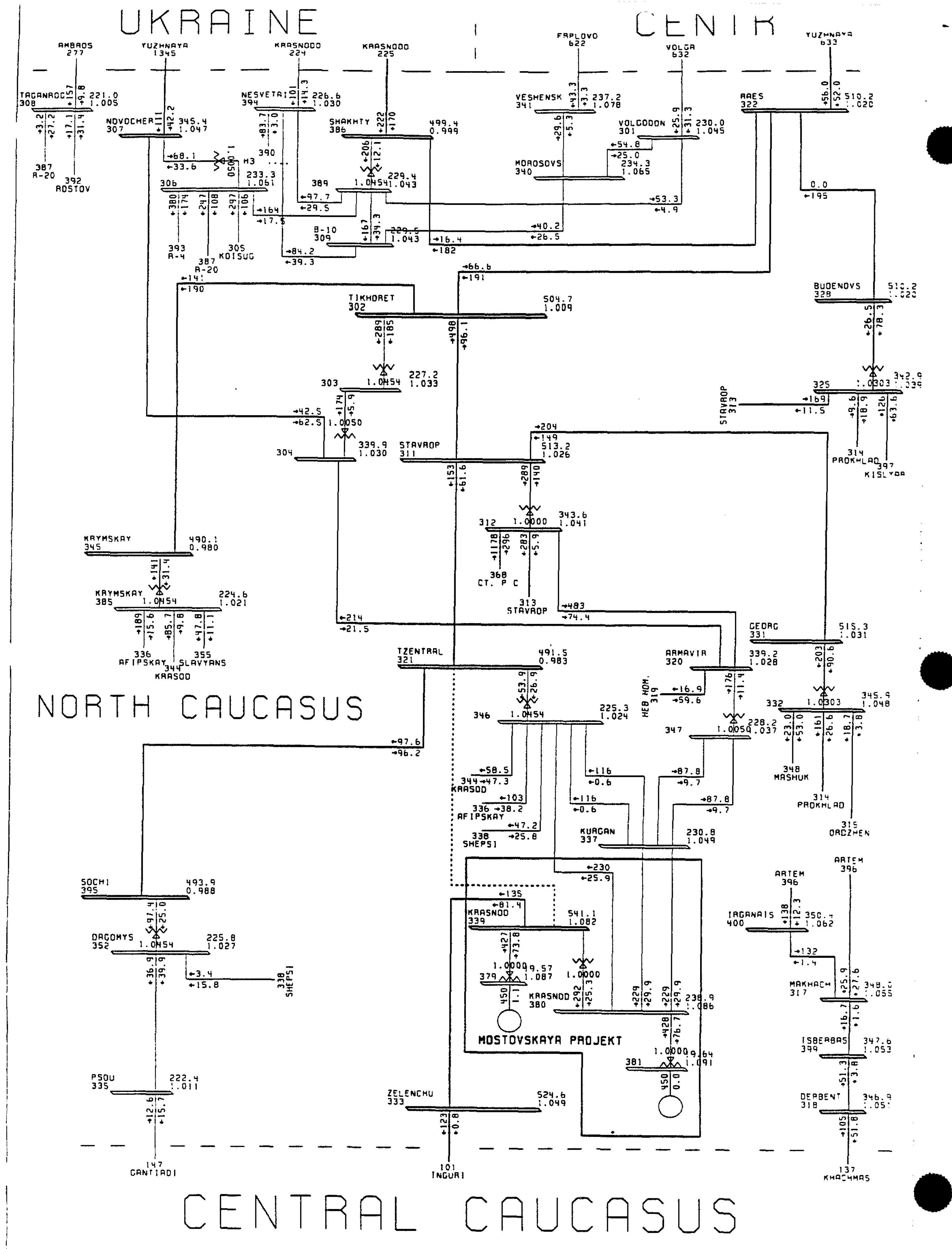


MOSTOVSKAYA PROJECT, PROJECT CASE (2-1-0)
LINE YUZHNAYA-RAES OUT
FIG. 19 MON, SEP 27 1965 14:48

POWER TECHNOLOGIES, INC

90 % RATEA
0.950UV 1.120OV
KV: ≤220 , ≤330 , ≤500

563

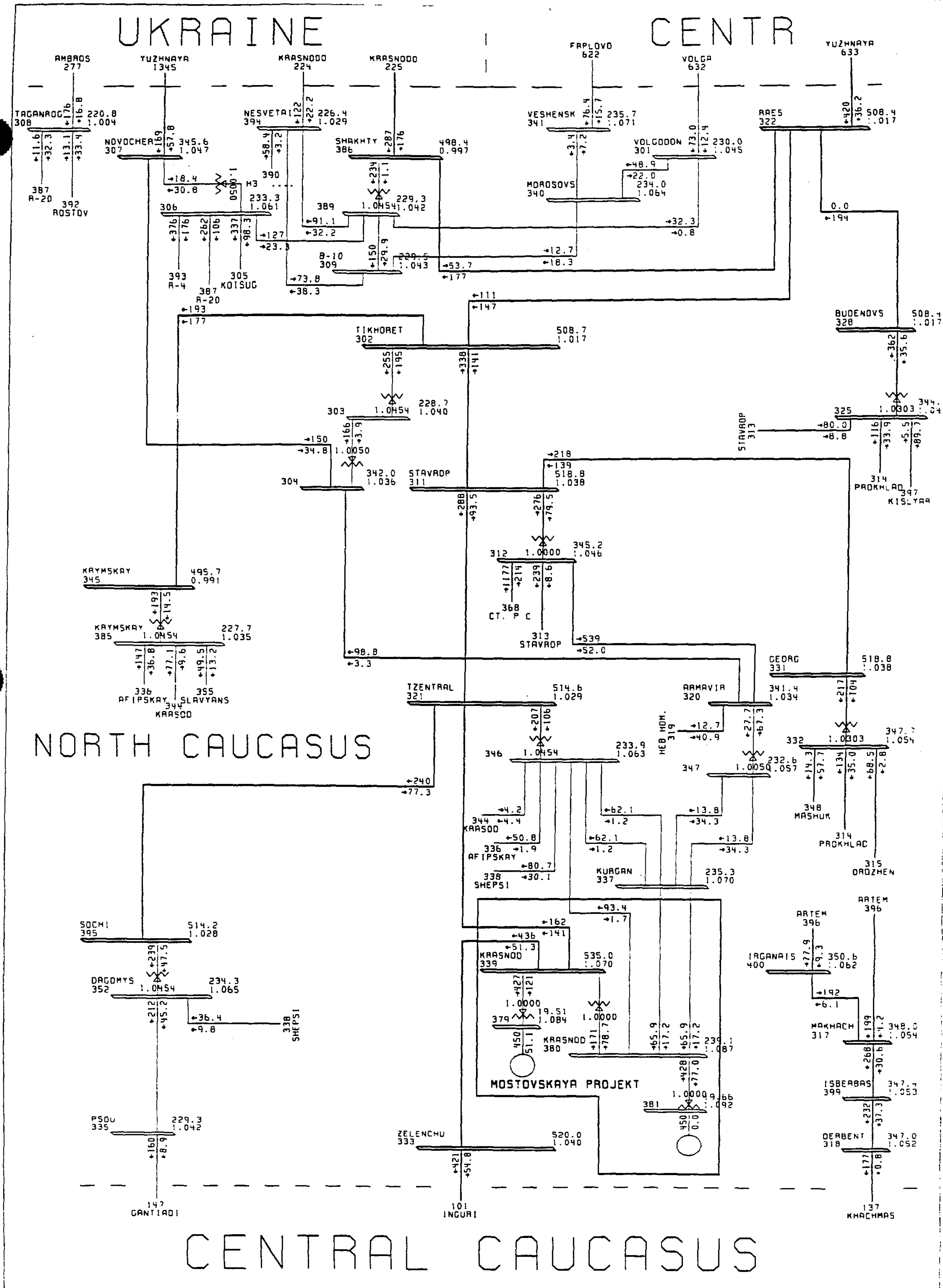


MOSTOVSKAYA PROJECT, PROJECT CASE (2-2-0)
LINE TZENTRAL-KRASNODAR OUT
FIG. 20 MON, SEP 27 1965 14:51

POWER TECHNOLOGIES, INC.

90 % RATED
0.950UV 1.120OV
KV: ≤220 , ≤330 , ≤500

34



MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-1)

POWER TECHNOLOGIES INC FIG. 21 MON, SEP 27 1965 14:54

90 % RATER
0.950UV 1.120UV
KV: ≤220 , ≤330 , ≤500

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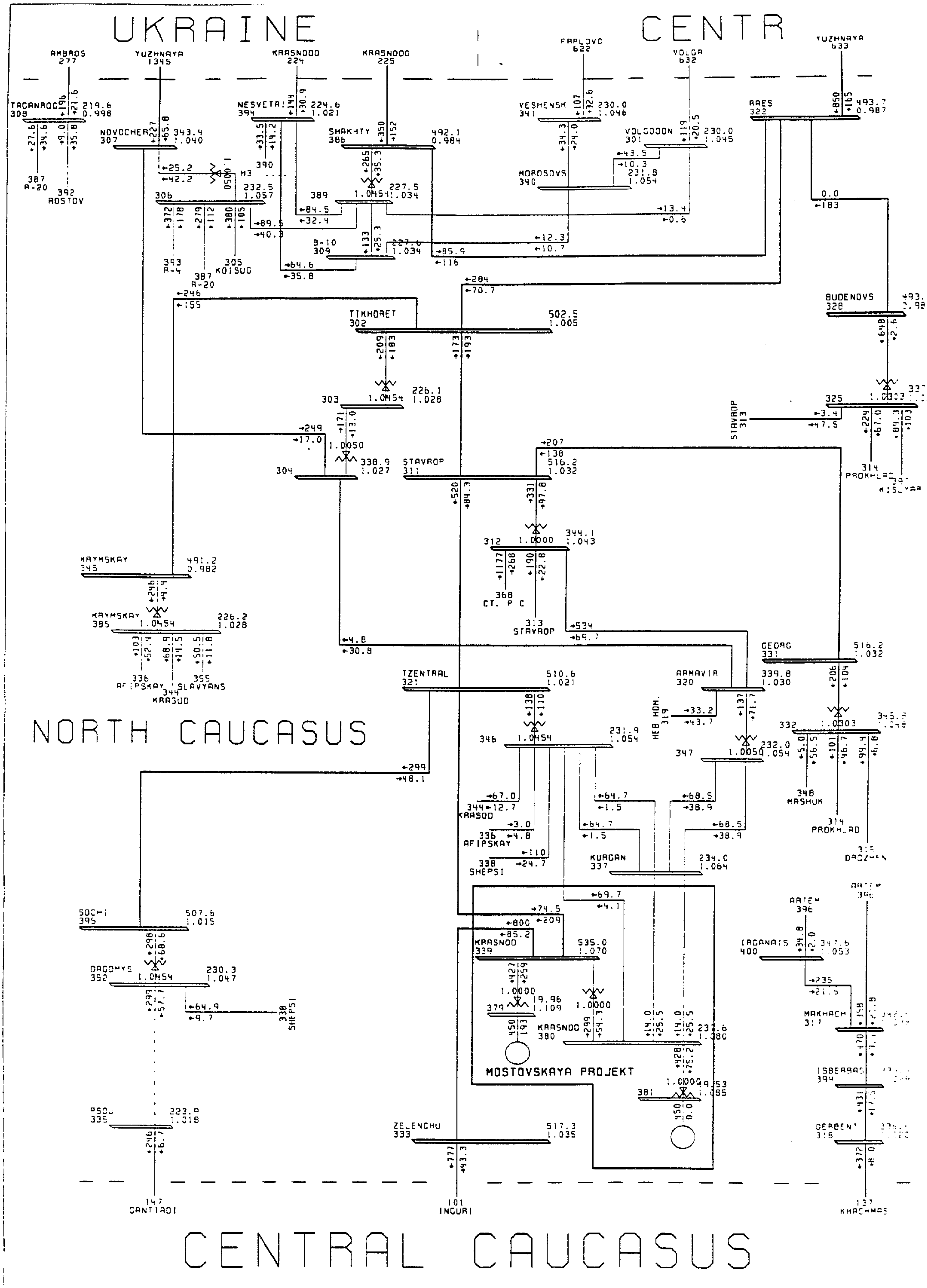
565

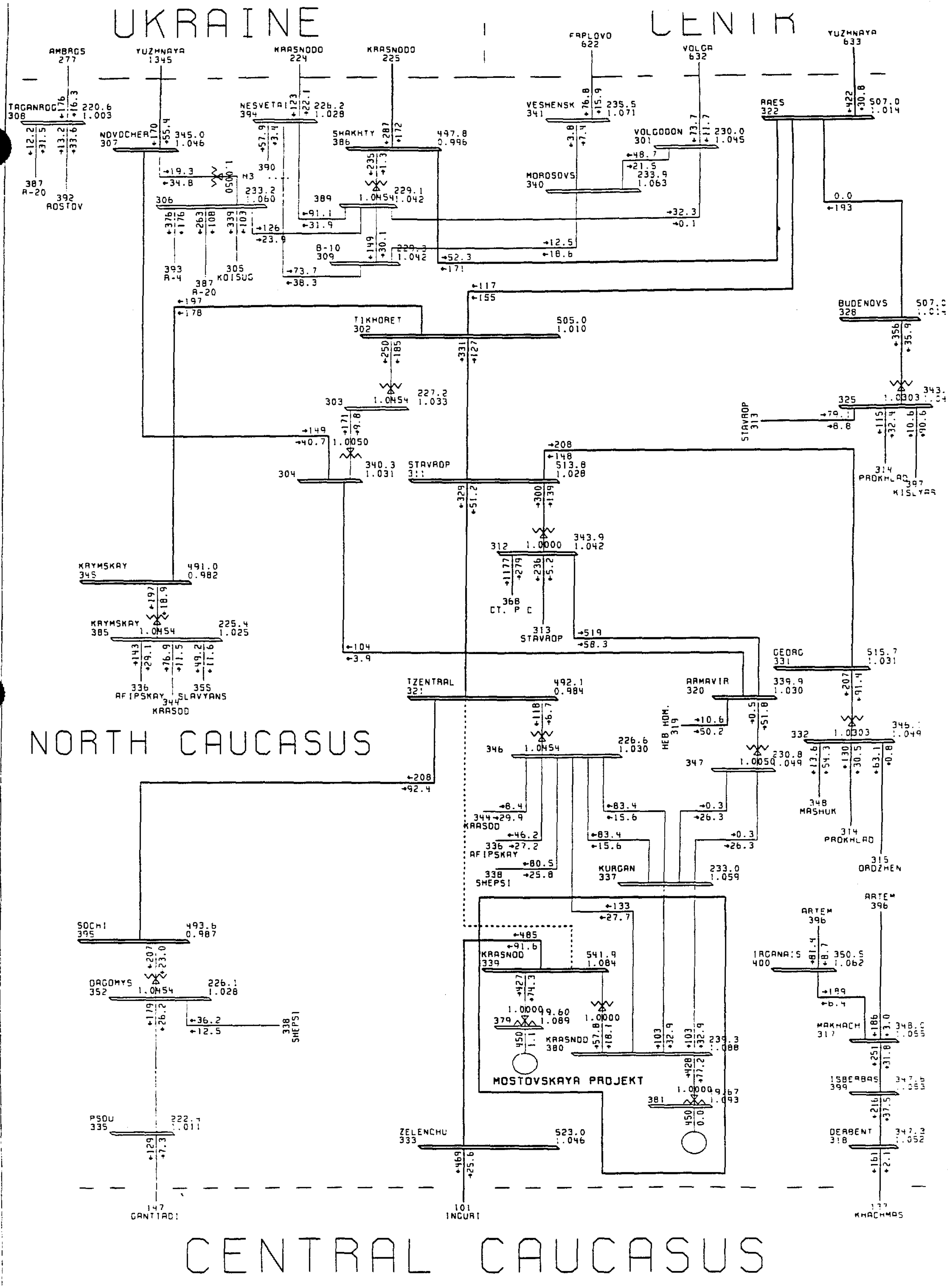


MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-2)

FIG. 22 MON. SEP 27 1965 15:04

90 % RATEA
0.950UV 1.120UV
KV: ≤220 . ≤330 . ≤500

566



MOSTOVSKAYA PROJECT, PROJECT CASE (2-1-1)
LINE TZENTRAL-KRASNODAR OUT
FIG. 23 MON, SEP 27 1965 15:07

90 % RATE A
0.950UV 1.120OV
KV: ≤220 .≤330 .≤500

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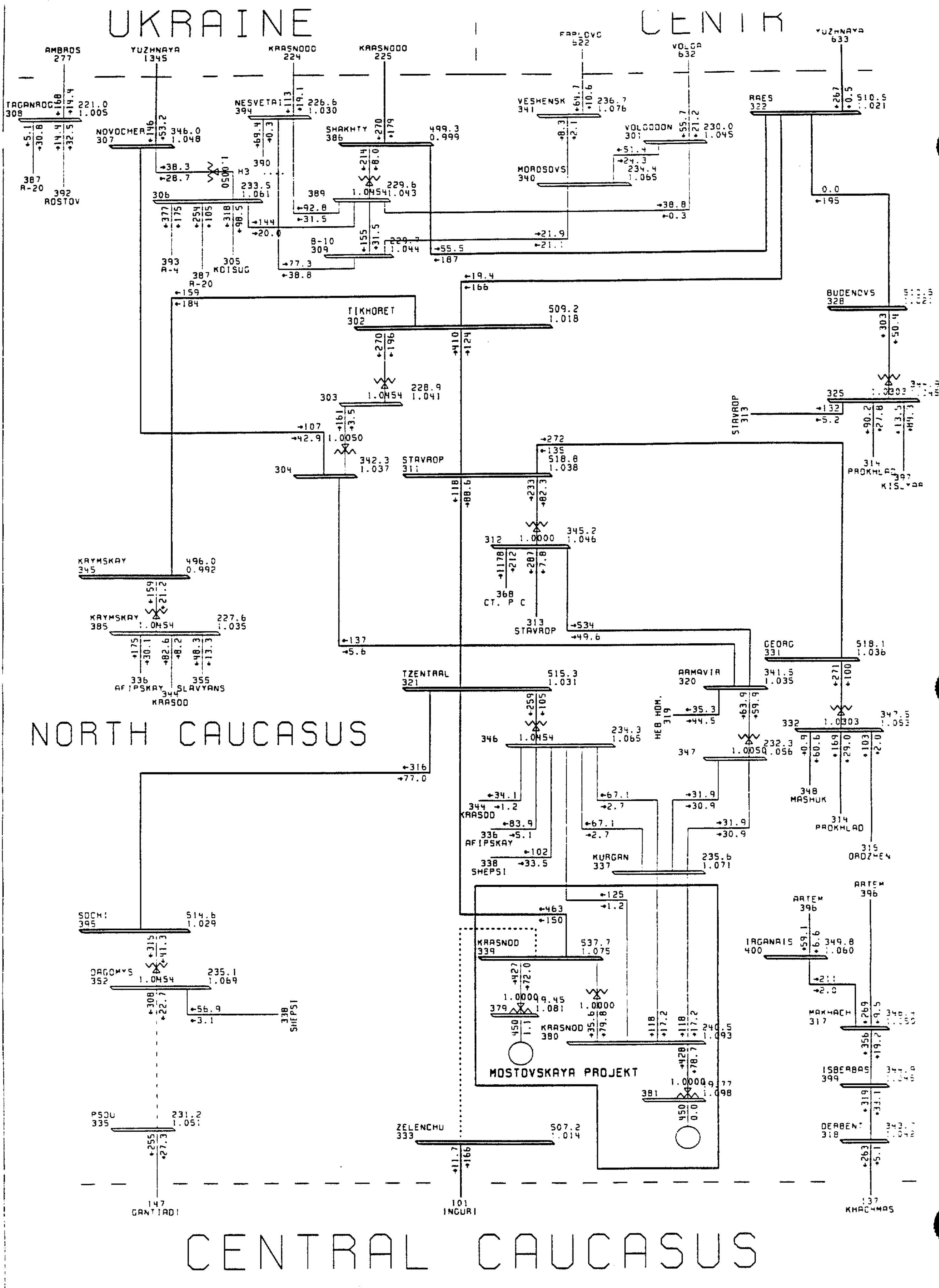
567

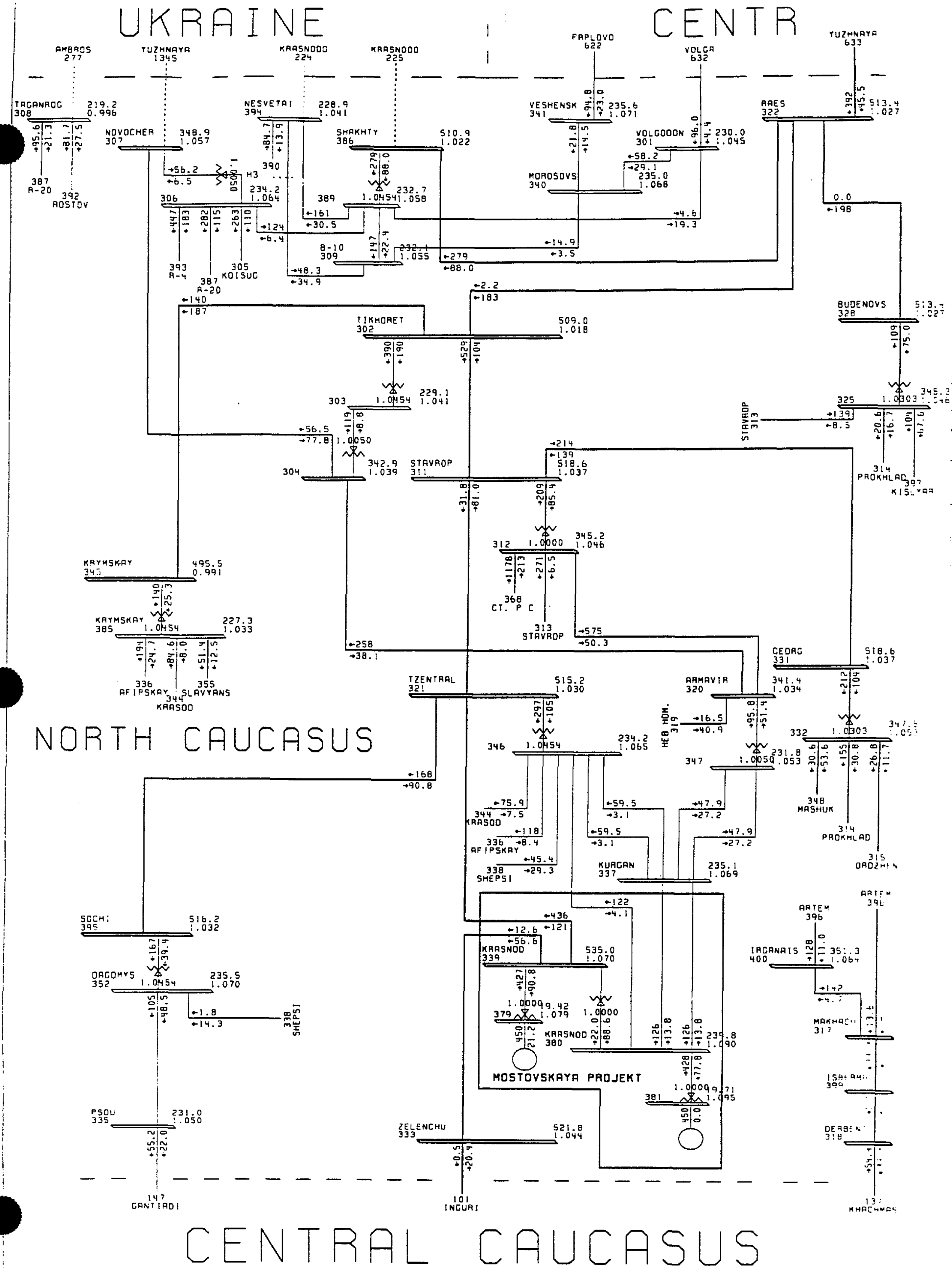


MOSTOVSKAYA PROJECT, PROJECT CASE (2-2-1)
LINE KRASNODAR-ZELENCHUC OUT
FIG. 24 MON, SEP 27 1965 15:11

90 % RATER
0.950 OV 1.120 OV
Kv: ≤220 . ≤330 . ≤500

POWER TECHNOLOGIES, INC.

568



MOSTOVSKAYA PROJECT, PROJECT CASE (2-3-0)
UKRAINE LINES OUT
FIG. 25 MON. SEP 27 1965 15:14

90 % RATES
0.950UV 1.120U
KV: ≤220 , ≤330 , ≤750

POWER TECHNOLOGIES, INC.

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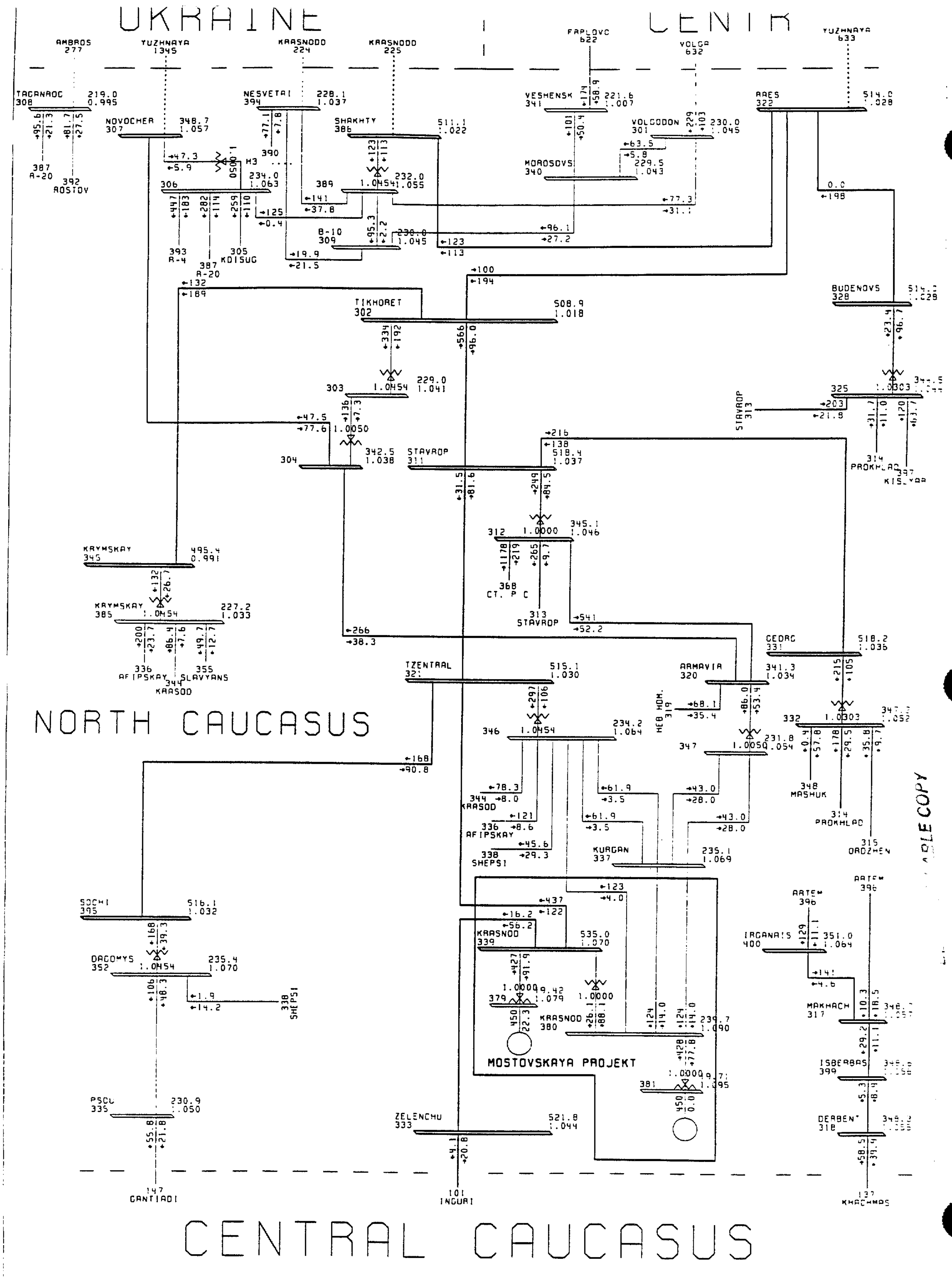
569

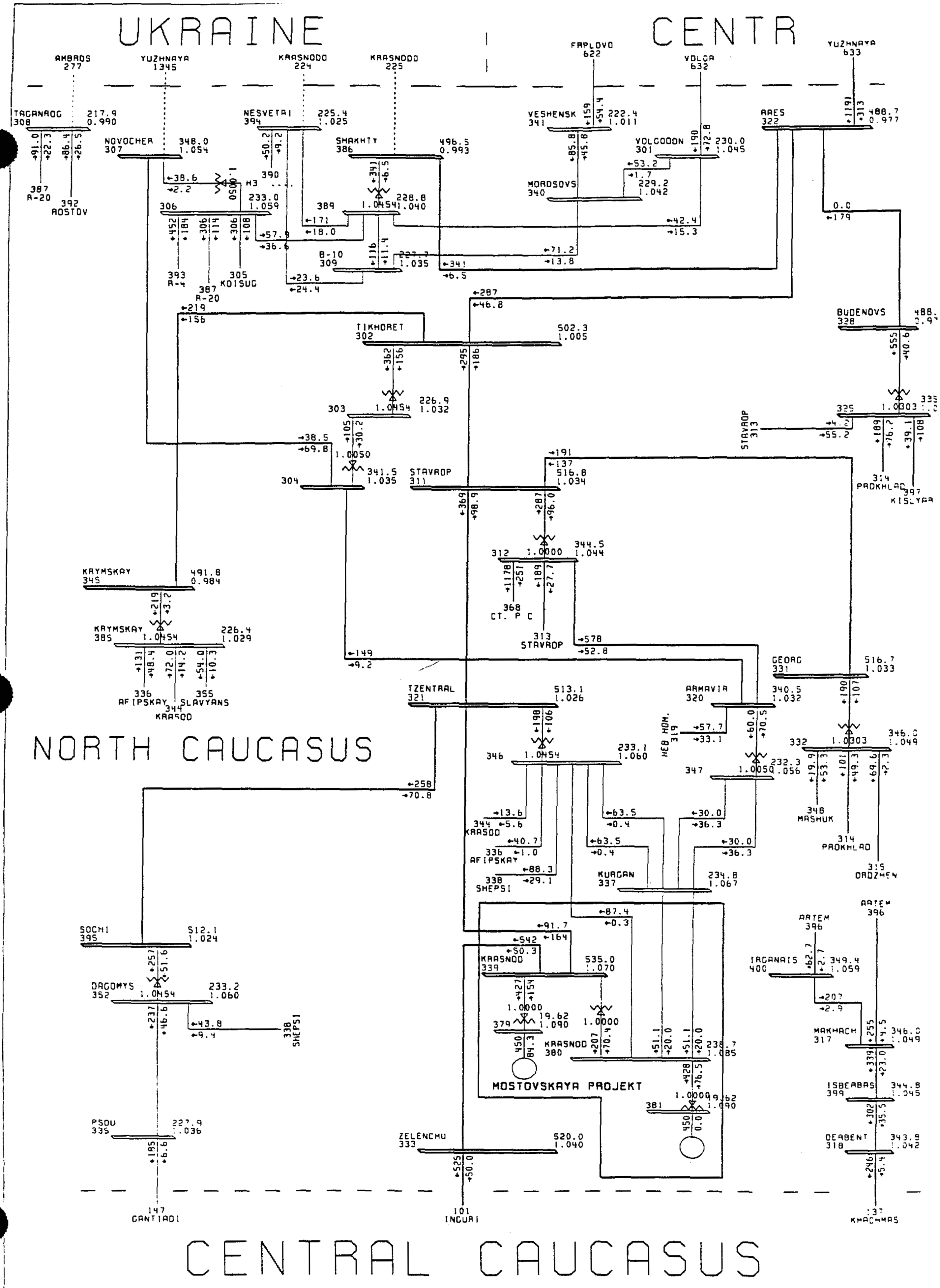


MOSTOVSKAYA PROJECT, PROJECT CASE (2-4-0)
UKRAINE LINES AND LINE YUZHNAYA-RAES OUT
FIG. 26 MON, SEP 27 1965 15:17

POWER TECHNOLOGIES INC.

90 % RATED
0.950 OV 1.120
KV: ≤220 ,≤330 ,≤500

570



MOSTOVSKAYA PROJECT, PROJECT CASE (2-3-1)
UKRAINE LINES OUT
FIG.27 MON, SEP 27 1965 15:21

POWER TECHNOLOGIES, INC.

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90 % BASE
0.950UV 1.120OV
KV: ≤220 , ≤330 , ≤500

571

MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-0)
3-PHASE FAULT KRASNODAR, LINE KRASNODAR-TZENTRAL OUT

POWER TECHNOLOGIES, INC.

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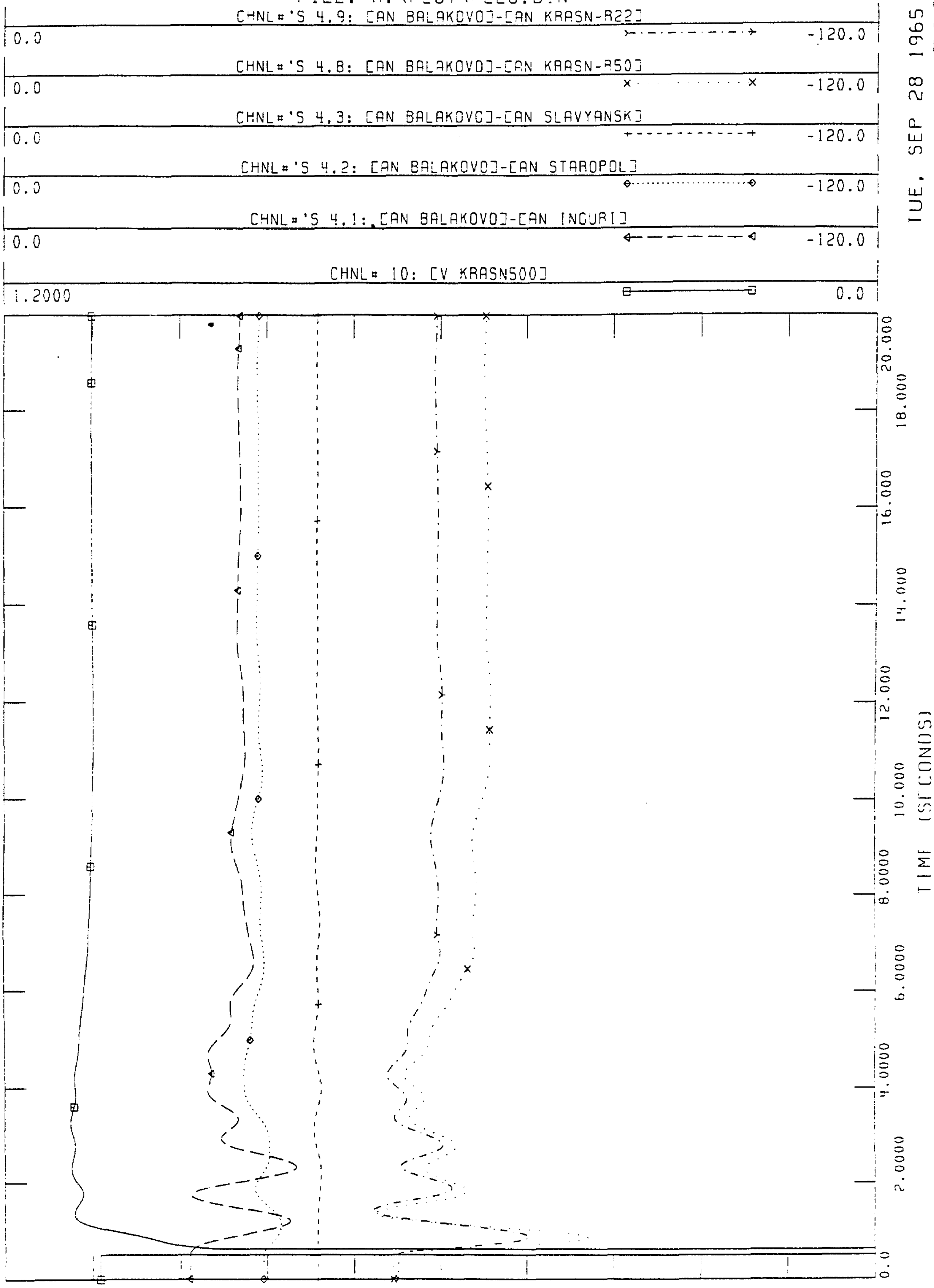

TUE. SEP 28 1965 13:07

FIG. 28

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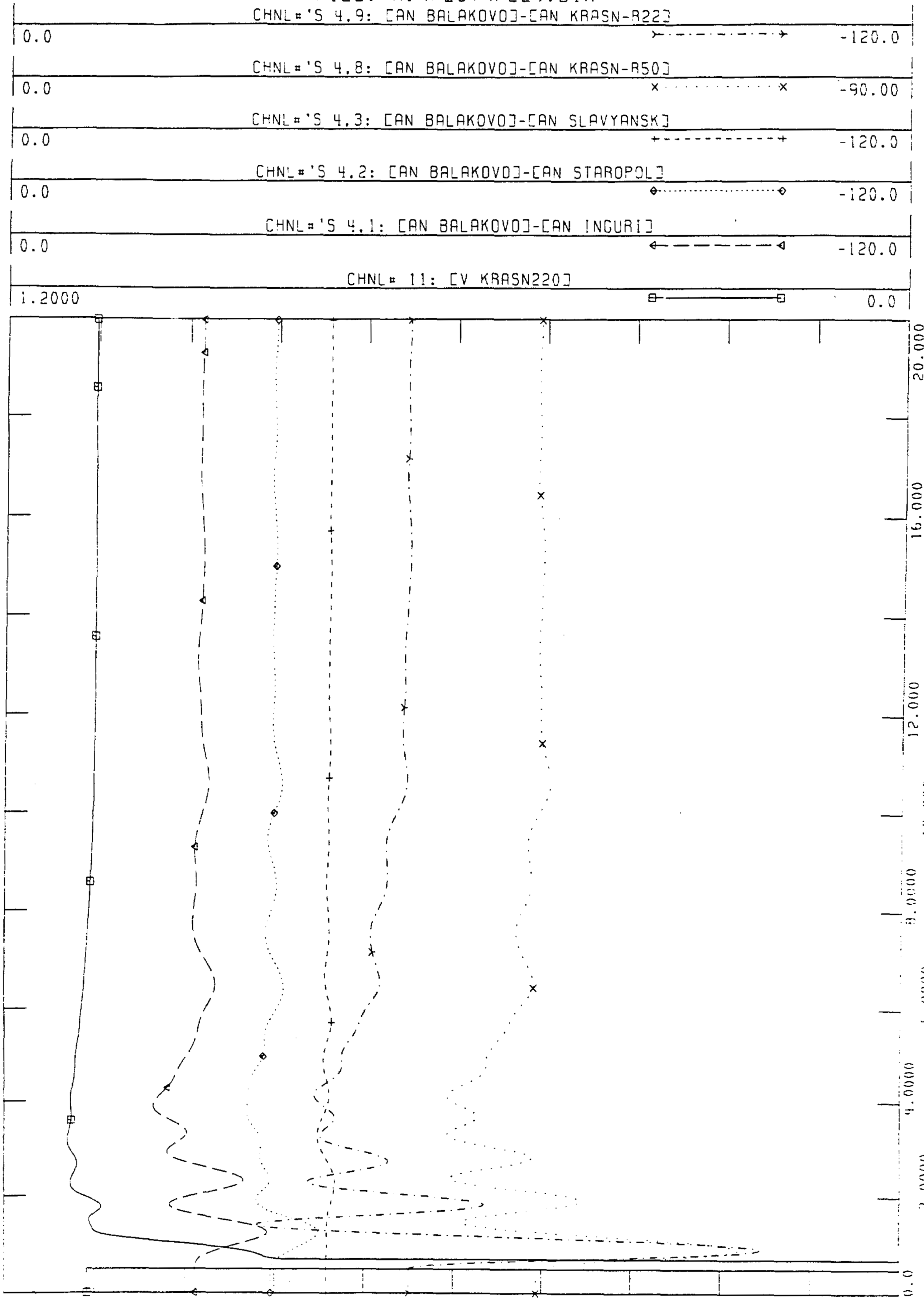
572

POWER TECHNOLOGIES, INC.

MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-0)
3-PHASE FAULT KRASNODAR 220, LINE KRASNODAR-TZENTRAL 220 OUT

FILE: A:\PLOT\PL29.BIN



TUE, SEP 28 1965 13:11

FIG. 29

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573

MOSTOVSKAYA PROJECT, PROJECT CASE (2-2-0)
3-PHASE FAULT KRASNODAR, LINE KRASNODAR-ZELENCHUC OUT

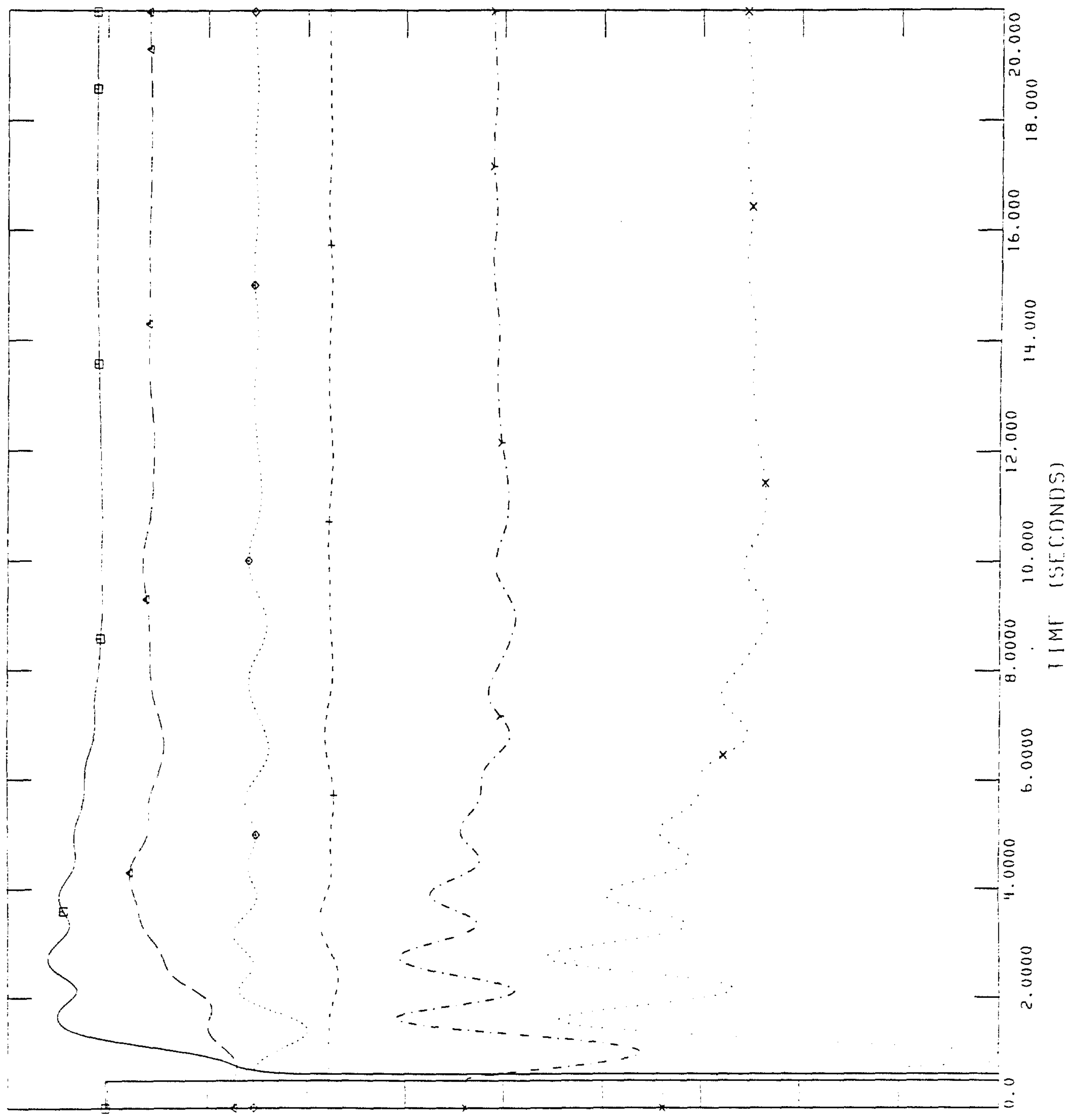
POWER TECHNOLOGIES, INC.

TUE, SEP 28 1965 13:13

FIG. 30

FILE: A:\PLOT\PL30.BIN

CHNL#'S 4.9: [AN BALAKOVO]-[AN KRASN-R22]	0.0	-120.0
CHNL#'S 4.8: [AN BALAKOVO]-[AN KRASN-R50]	0.0	-90.00
CHNL#'S 4.3: [AN BALAKOVO]-[AN SLAVYANSK]	0.0	-120.0
CHNL#'S 4.2: [AN BALAKOVO]-[AN STAROPOL]	0.0	-120.0
CHNL#'S 4.1: [AN BALAKOVO]-[AN INGURI]	0.0	-120.0
CHNL# 10: [V KRASN500]	1.2000	0.0

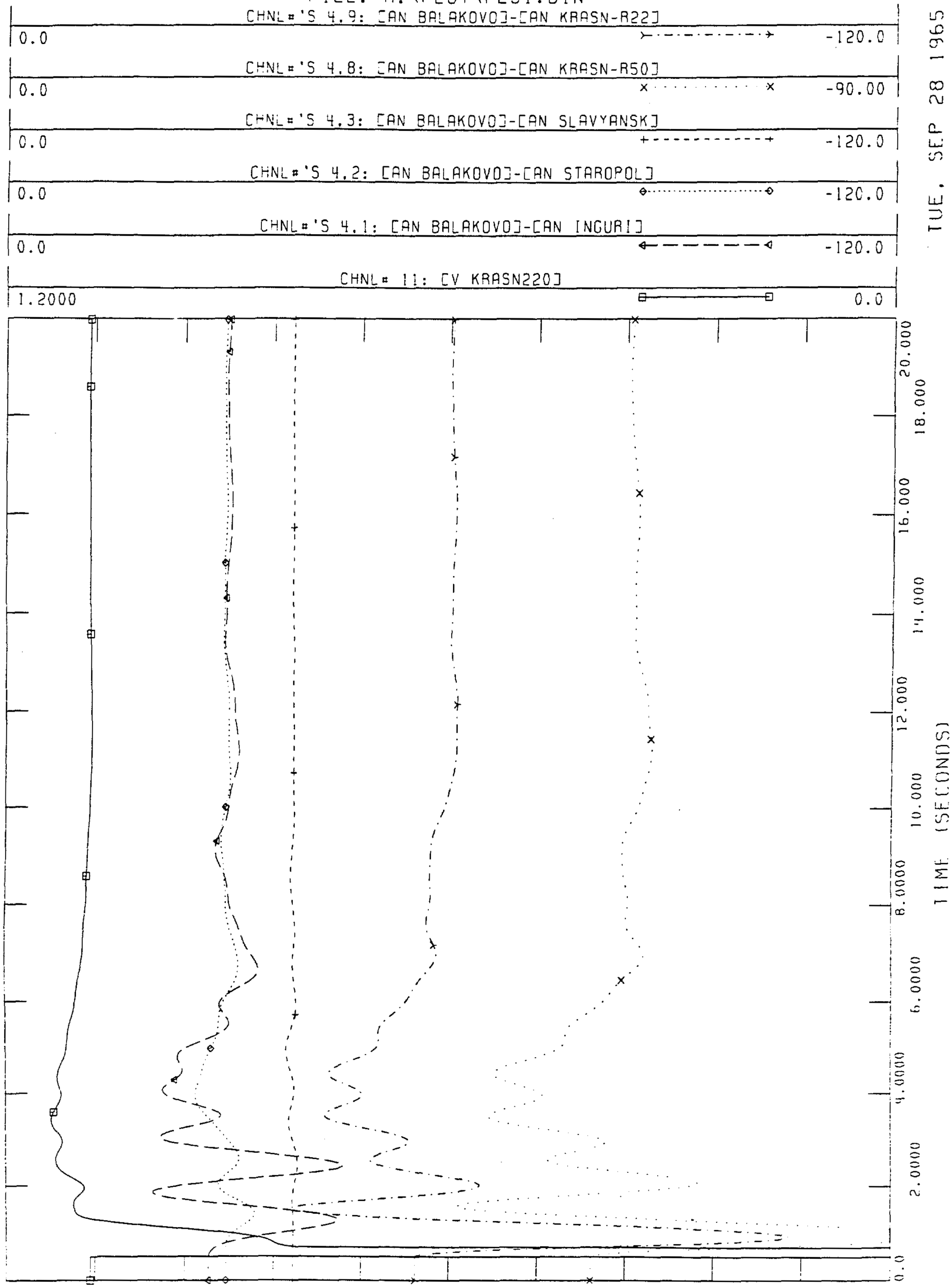


574

POWER TECHNOLOGIES, INC.

MOSTOVSKAYA PROJECT, PROJECT CASE (2-2-0)
3-PHASE FAULT KRASNODAR 220, LINE KRASNODAR-TZENTRAL 220 OUT

FILE: A:\PLOT\PL31.BIN



TUE, SEP 28 1965 13:15

FIG. 31

575

MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-0)
3-PHASE FAULT RAES, LINE RAES-YUZNAYA OUT

POWER TECHNOLOGIES, INC.

TUE, SEP 28 1965 13:18

FIG. 32

FILE: A:\PLOT\PL32.BIN

CHNL#'S 4.9: [AN BALAKOVO]-[AN KRASN-A22] 0.0 -120.0

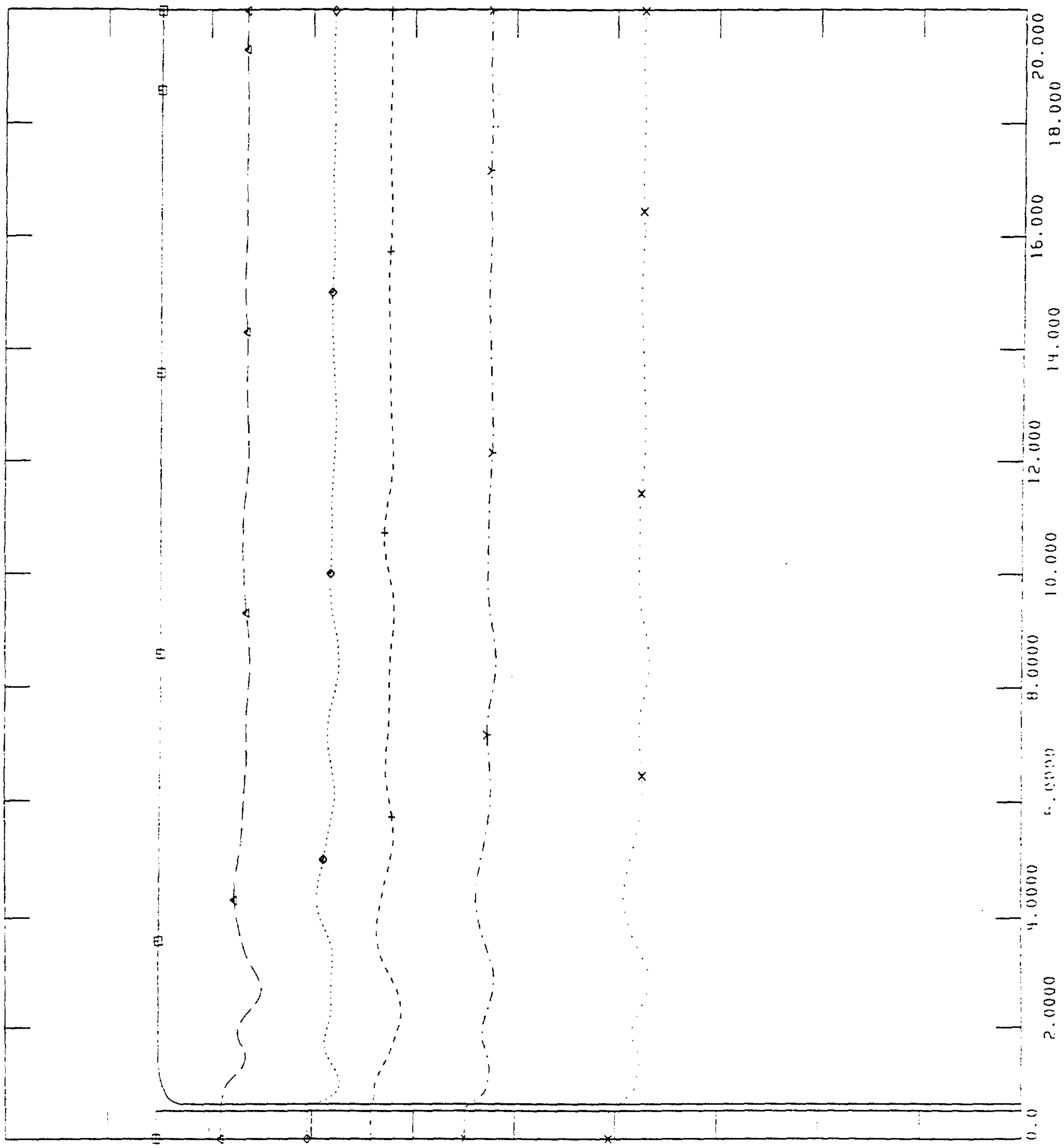
CHNL#'S 4.8: [AN BALAKOVO]-[AN KRASN-A50] 0.0 -90.00

CHNL#'S 4.3: [AN BALAKOVO]-[AN SLAVYANSK] 0.0 -120.0

CHNL#'S 4.2: [AN BALAKOVO]-[AN STAROPOL] 0.0 -120.0

CHNL#'S 4.1: [AN BALAKOVO]-[AN INGURI] 0.0 -120.0

CHNL# 5: [V RAES] 1.2000 0.0



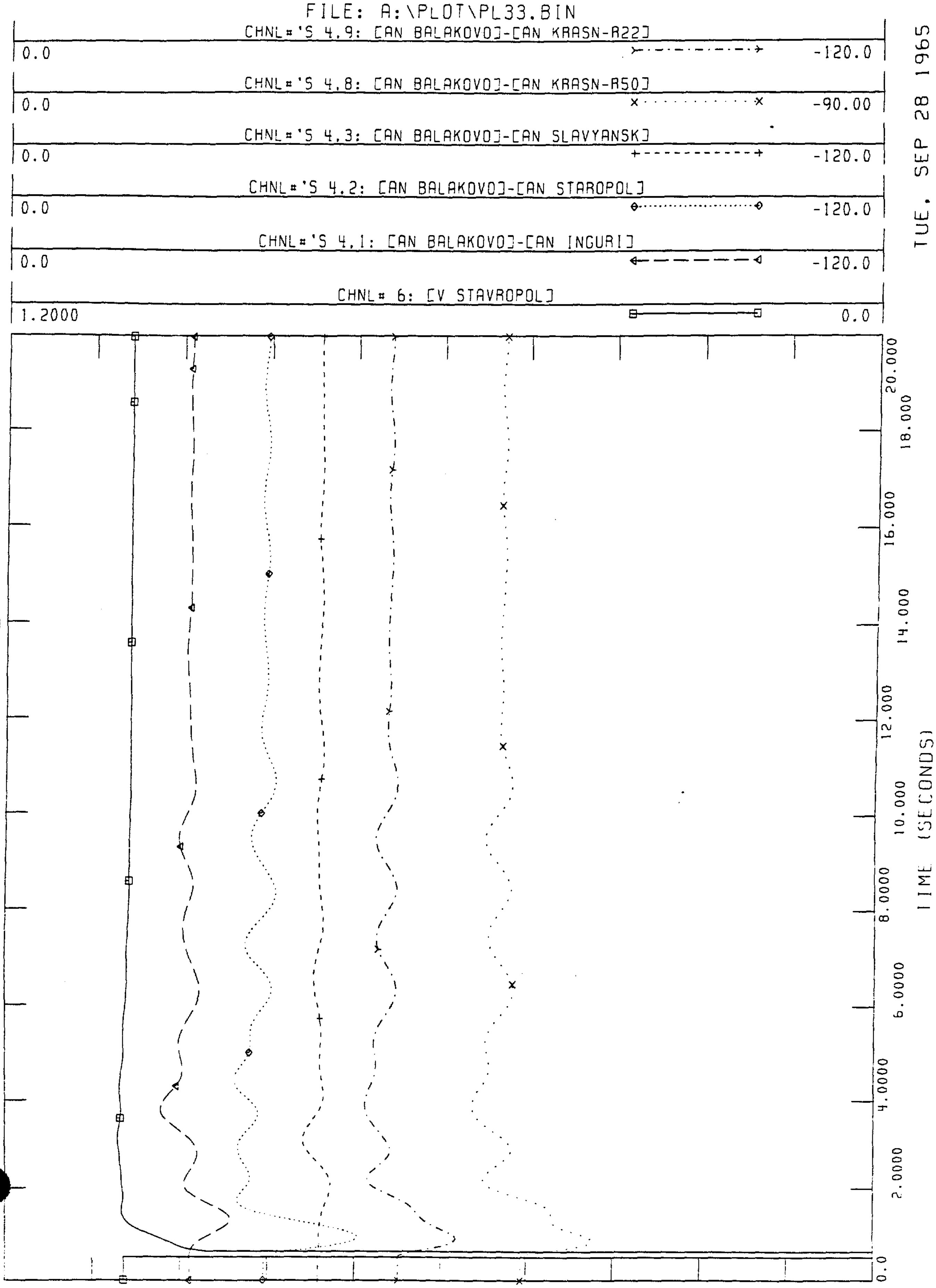
576

MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-0)
3-PHASE FAULT STAVROPOL, LINE STAVROPOL-TZENTRAL OUT

POWER TECHNOLOGIES, INC.

TUE, SEP 28 1965 13:24

FIG. 33



577

POWER TECHNOLOGIES, INC.

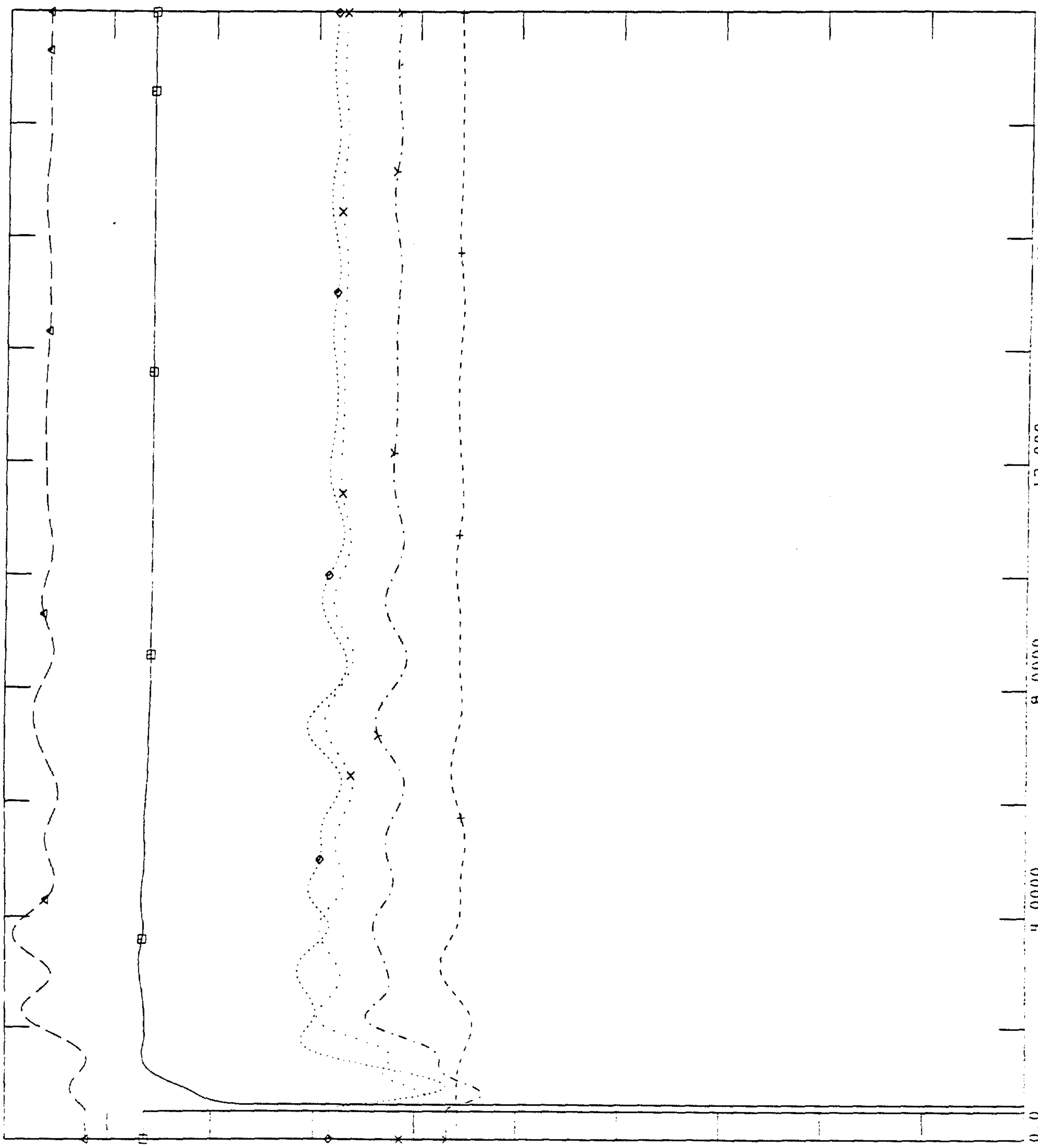
MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-1)
3-PHASE FAULT STAVROPOL, LINE STAVROPOL-TZENTRAL OUT

TUE, SEP 28 1965 13:35

FIG. 34

FILE: A:\PLOT\PL34.BIN

CHNL#'S 4.9: [AN BALAKOVO]-[AN KRASN-R22]		
60.000		-60.00
CHNL#'S 4.8: [AN BALAKOVO]-[AN KRASN-R50]		
60.000		-60.00
CHNL#'S 4.3: [AN BALAKOVO]-[AN SLAVYANSK]		
60.000		-60.00
CHNL#'S 4.2: [AN BALAKOVO]-[AN STAROPOL]		
60.000		-60.00
CHNL#'S 4.1: [AN BALAKOVO]-[AN INGURI]		
60.000		-60.00
CHNL# 6: [V STAVROPOL]		
1.2000		0.0



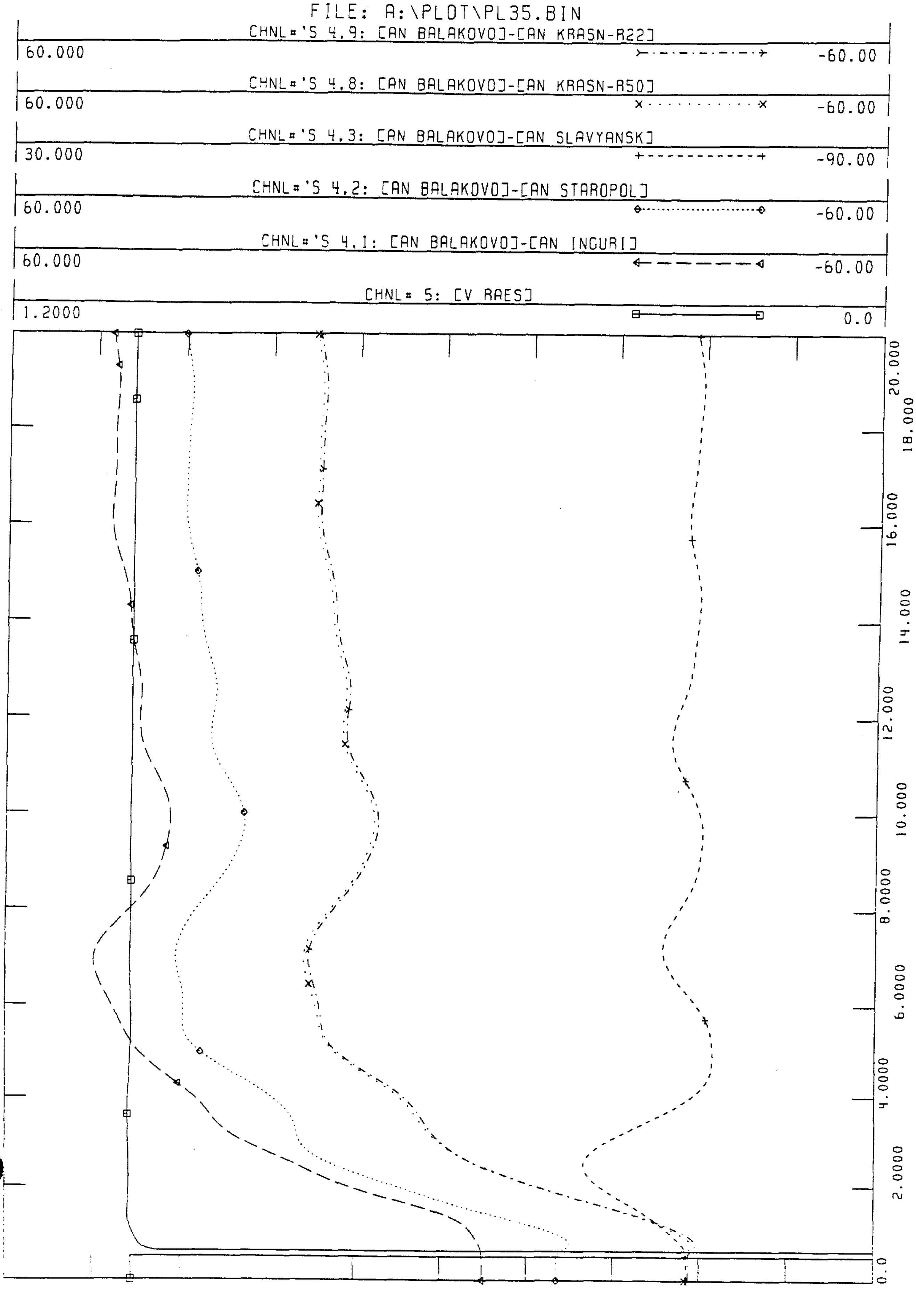
578

POWER TECHNOLOGIES, INC.

MOSTOVSKAYA PROJECT, PROJECT CASE (2-3-0)
3-PHASE FAULT RAES, LINE RAES-YUZNAYA OUT

TUE, SEP 28 1965 13:50

FIG. 35



579

POWER TECHNOLOGIES, INC.

MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-1)
3-PHASE FAULT KRASNODAR, LINE KRASNODAR-ZELENCHUK OUT

TUE. SEP 28 1965 13:57

FIG. 36

FILE: A:\PLOT\PL36.BIN

CHNL#'S 4.9: [AN BALAKOVO]-[AN KRASN-A22] 60.000 -30.00

CHNL#'S 4.8: [AN BALAKOVO]-[AN KRASN-A50] 60.000 -30.00

CHNL#'S 4.3: [AN BALAKOVO]-[AN SLAVYANSK] 60.000 -30.00

CHNL#'S 4.2: [AN BALAKOVO]-[AN STAROPOL] 60.000 -30.00

CHNL#'S 4.1: [AN BALAKOVO]-[AN INGURI] 90.000 -30.00

CHNL# 10: [V KRASN500] 1.2000 0.0

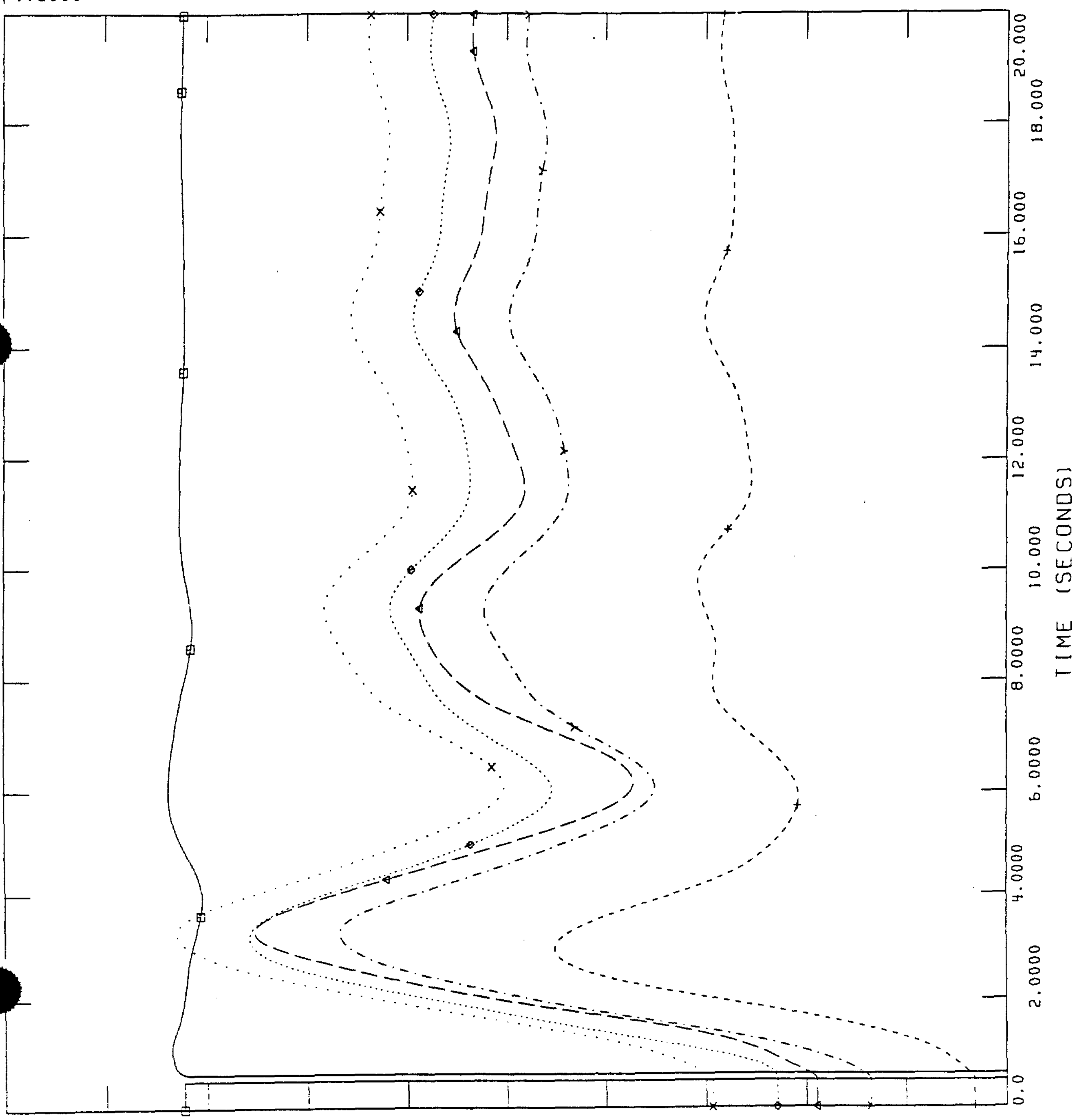
580

MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-2)
3-PHASE FAULT RAES, LINE RAES-YUZNAYA OUT

POWER TECHNOLOGIES, INC.

FILE: A:\PLOT\PL37.BIN

CHNL#'S 4.9: [AN BALAKOVO]-[AN KRASN-A22]	160.00	40.000
CHNL#'S 4.8: [AN BALAKOVO]-[AN KRASN-A50]	160.00	40.000
CHNL#'S 4.3: [AN BALAKOVO]-[AN SLAVYANSK]	160.00	40.000
CHNL#'S 4.2: [AN BALAKOVO]-[AN STAROPOL]	160.00	40.000
CHNL#'S 4.1: [AN BALAKOVO]-[AN INGURI]	210.00	90.000
CHNL# 5: [V RAES]	1.2000	0.0



TUE. SEP 28 1965 14:26

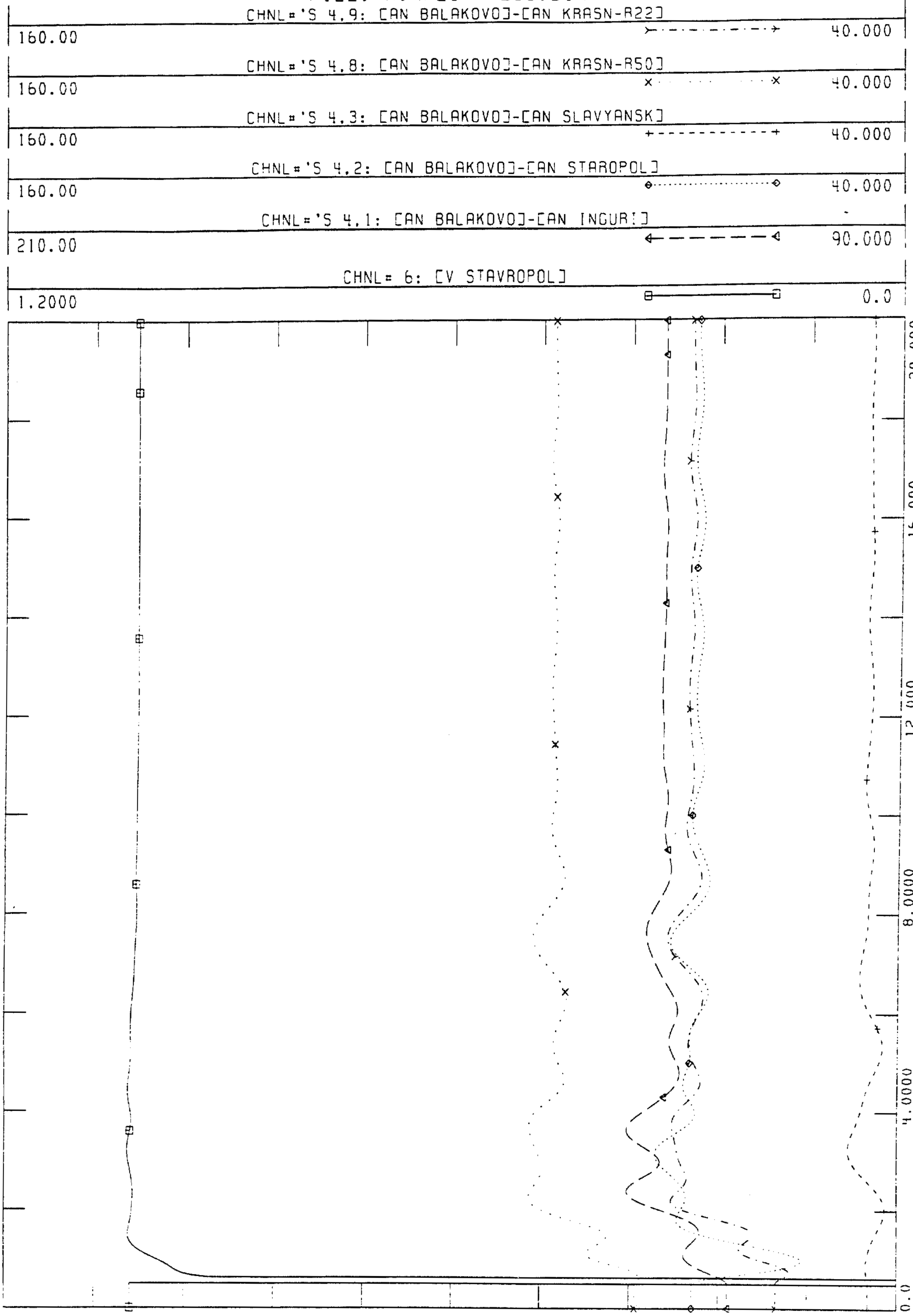
FIG. 37

581

POWER TECHNOLOGIES, INC.

MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-2)
3-PHASE FAULT STAVROPOL, LINE STAVROPOL-TZENTRAL

FILE: A:\PLOT\PL..BIN



TUE, SEP 28 1965 14:25

FIG. 38

582

POWER TECHNOLOGIES, INC.

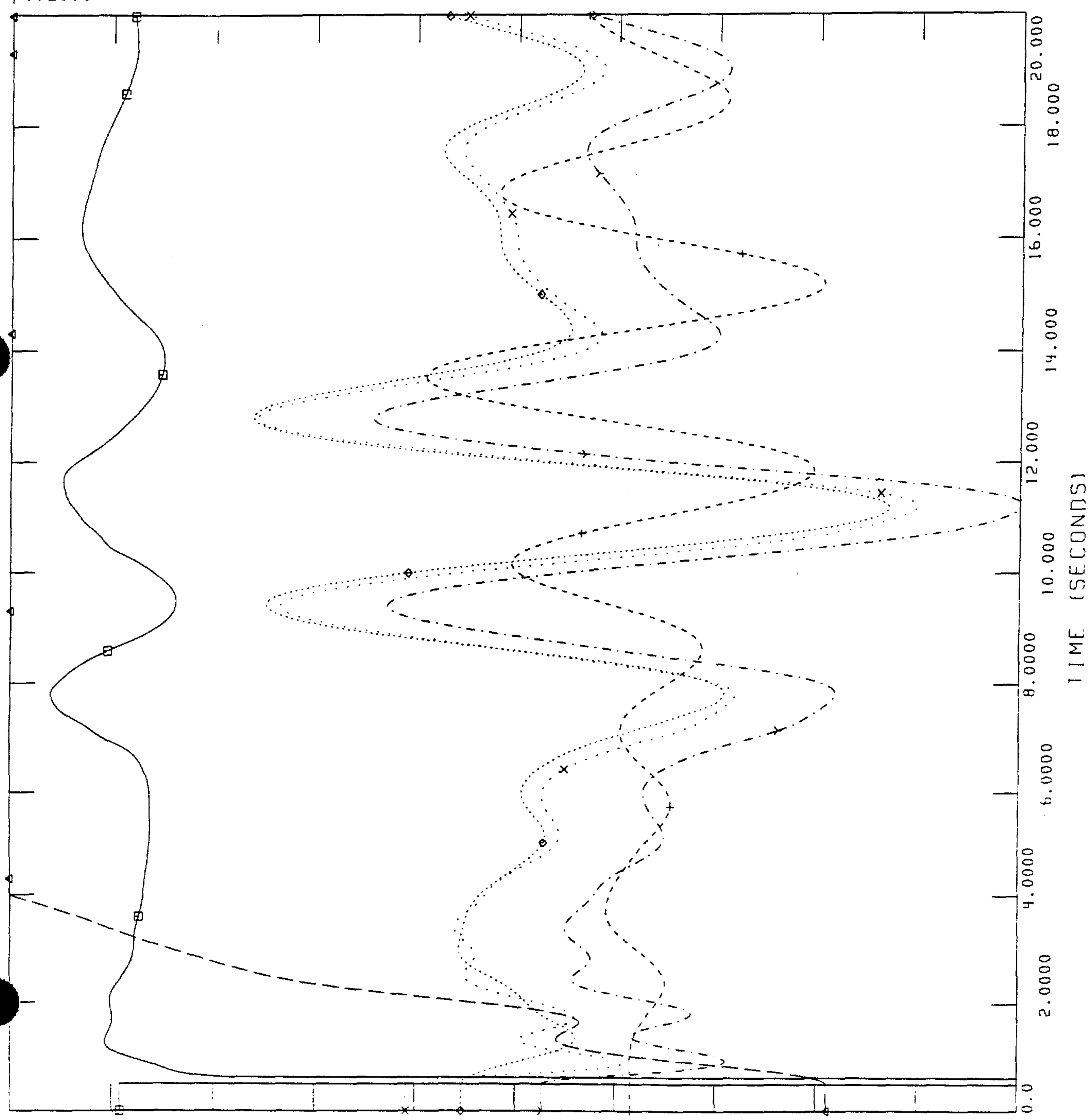
MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-2)
3-PHASE FAULT KRASNODAR, LINE KRASNODAR-ZELENCHUK OUT

TUE, SEP 28 1965 14:24

FIG. 39

FILE: A:\PLOT\PL39.BIN

130.00	CHNL#'S 4.9: [AN BALAKOVO]-[AN KRASN-R22]	-10.00
130.00	CHNL#'S 4.8: [AN BALAKOVO]-[AN KRASN-R50]	-10.00
130.00	CHNL#'S 4.3: [AN BALAKOVO]-[AN SLAVYANSK]	-10.00
130.00	CHNL#'S 4.2: [AN BALAKOVO]-[AN STAROPOL]	-10.00
210.00	CHNL#'S 4.1: [AN BALAKOVO]-[AN INGURI]	90.000
1.2000	CHNL# 10: [V KRASN500]	0.0

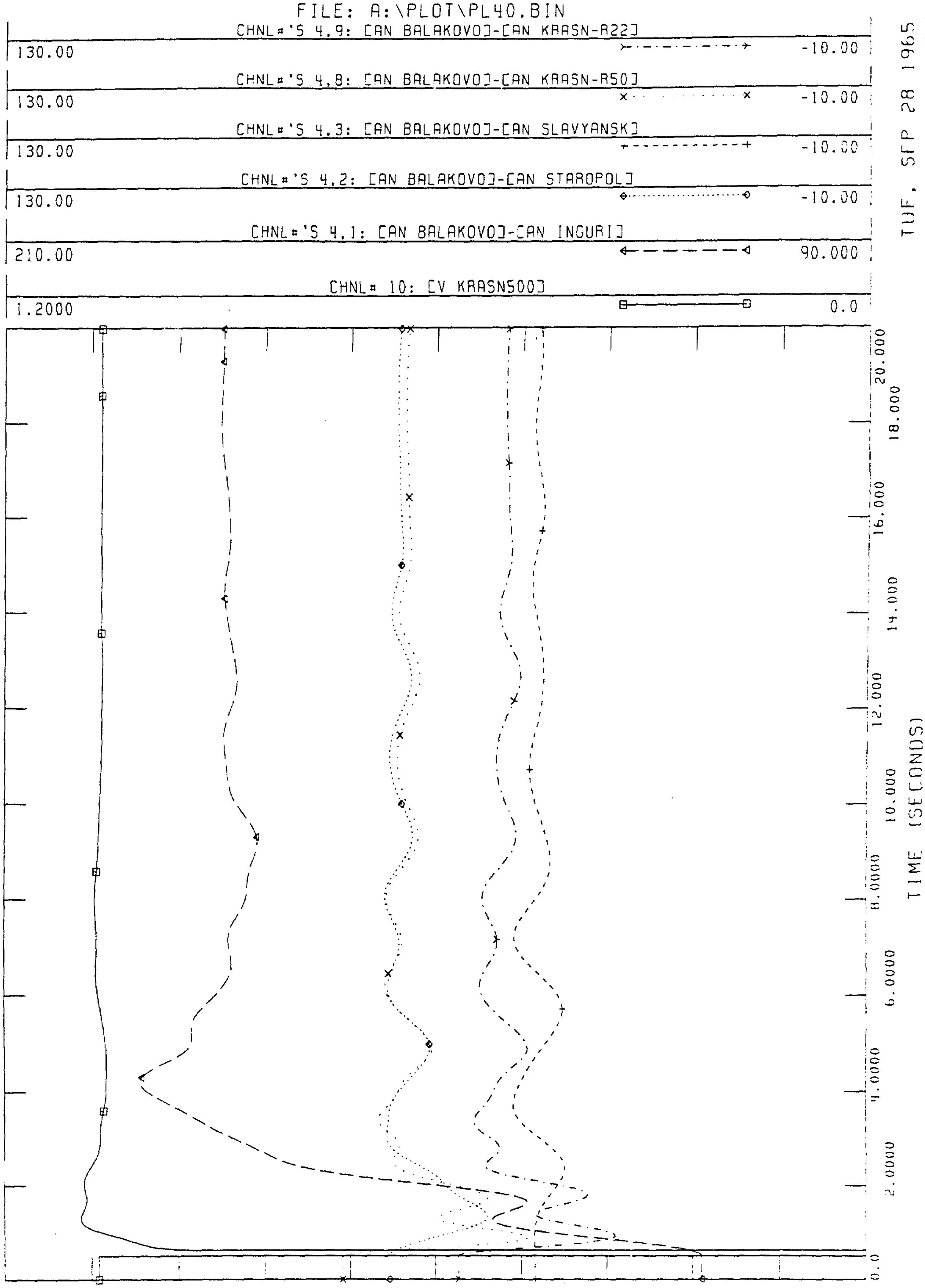


583

MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-2)
3-PHASE FAULT KRASNODAR, LINE KRASNODAR-ZELENCHUK OUT

POWER TECHNOLOGIES, INC.

FILE: A:\PLOT\PL40.BIN



TUE. SEP 28 1965 14:22

FIG. 40

584

UNBALANCES APPLIED:

LINE TO GROUND FAULT AT BUS 339 [KRASNOD 500] PHASE 1
L-G Z = 0.0000 0.0000

LINE TO LINE TO GROUND FAULT AT BUS 339 [KRASNOD 500] EXCLUDED PHASE 1
L-L Z = 0.0000 0.0000 L-G Z = 0.0000 0.0000

SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

BUS	NAME	BSKV	ZERO		POSITIVE		NEGATIVE	
339	KRASNOD	500	0.00000	*********	0.00107	0.01260	0.00107	0.01260

THREE PHASE FAULT AT BUS 339 [KRASNOD 500]:

SEQUENCE PHASE	/V0/ /VA/	AN(V0) AN(VA)	/V+/ /VB/	AN(V+) AN(VB)	/V-/ /VC/	AN(V-) AN(VC)	/3V0/	AN(3V0)
339 (KV L-G)	72.730	-172.88	32.472	6.03	32.472	6.03	218.191	-172.88
KRASNOD 500	7.896	-163.80	105.199	-173.21	105.199	-173.21		

SEQUENCE PHASE	/I0/ /IA/	AN(I0) AN(IA)	/I+/ /IB/	AN(I+) AN(IB)	/I-/ /IC/	AN(I-) AN(IC)	/3I0/	AN(3I0)
FROM 321 0	0.0	0.00	2661.3	-89.50	331.2	103.36	0.0	0.00
TZENTRAL 500	2339.6	-91.31	2777.0	157.04	2896.8	25.69		
FROM 333 0	0.0	0.00	2048.6	-82.11	247.9	102.08	0.0	0.00
ZELENCHU 500	1801.5	-82.68	2168.1	163.80	2197.5	32.54		
FROM 379 1	0.0	0.00	2026.4	-74.81	217.5	96.33	0.0	0.00
18.0	1811.8	-73.75	2169.4	169.66	2114.6	39.68		
FROM 380 0	0.0	0.00	2050.5	-85.25	231.8	100.38	0.0	0.00
KRASNOD 220	1819.9	-85.97	2156.5	160.37	2193.6	29.82		

SUM OF CONTRIBUTIONS INTO BUS 339 [KRASNOD 500]:

339	0.0	0.00	8747.4	-83.40	1027.3	100.89	0.0	0.00
KRASNOD 500	7723.3	-83.97	9239.4	162.35	9364.8	31.40		

CONTRIBUTIONS EQUIVALENT POSITIVE SEQUENCE ADMITTANCE 6.7112 -673.4161

FAULT CURRENT AT BUS 339 [KRASNOD 500]:

339	0.0	0.00	8747.4	-83.40	1027.3	100.89	0.0	0.00
KRASNOD 500	7723.3	-83.97	9239.4	162.35	9364.8	31.40		

POSITIVE SEQUENCE EQUIVALENT FAULT ADMITTANCE 6.7112 -673.4161

Figure 41
(14 pages)

UNBALANCES APPLIED:

LINE TO GROUND FAULT AT BUS 380 [KRASNOD 220] PHASE 1
L-G Z = 0.0000 0.0000

LINE TO LINE TO GROUND FAULT AT BUS 380 [KRASNOD 220] EXCLUDED PHASE 1
L-L Z = 0.0000 0.0000 L-G Z = 0.0000 0.0000

SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

BUS	NAME	BSKV	ZERO		POSITIVE		NEGATIVE	
380	KRASNOD	220	0.00000	0.39744	0.00167	0.01600	0.00167	0.01600

1 PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E FRI OCT 06, 1995 16:03
MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-0)

THREE PHASE FAULT AT BUS 380 [KRASNOD 220]:

SEQUENCE PHASE	/V0/ /VA/	AN(V0) AN(VA)	/V+/ /VB/	AN(V+) AN(VB)	/V-/ /VC/	AN(V-) AN(VC)	/3V0/	AN(3V0)
380 (KV L-G)	0.000	0.00	0.000	0.00	0.000	0.00	0.000	0.00
KRASNOD 220	0.000	0.00	0.000	0.00	0.000	0.00		

SEQUENCE PHASE	/I0/ /IA/	AN(I0) AN(IA)	/I+/ /IB/	AN(I+) AN(IB)	/I-/ /IC/	AN(I-) AN(IC)	/3I0/	AN(3I0)
MACHINE 1	0.0	0.00	843.2	-88.29	0.0	0.00	0.0	0.00
	843.2	-88.29	843.2	151.71	843.2	31.71		
FROM 337 1	0.0	0.00	1953.5	-82.98	0.0	0.00	0.0	0.00
KURGAN 220	1953.5	-82.98	1953.5	157.02	1953.5	37.02		
FROM 337 2	0.0	0.00	1953.5	-82.98	0.0	0.00	0.0	0.00
KURGAN 220	1953.5	-82.98	1953.5	157.02	1953.5	37.02		
FROM 339 0	0.0	0.00	6307.5	-85.57	0.0	0.00	0.0	0.00
KRASNOD 500	6307.5	-85.57	6307.5	154.43	6307.5	34.43		
FROM 381 1	0.0	0.00	5095.0	-76.30	0.0	0.00	0.0	0.00
18.0	5095.0	-76.30	5095.0	163.70	5095.0	43.70		
FROM 8765 1	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00
ZILP220 220	0.0	0.00	0.0	0.00	0.0	0.00		
FROM 8765 2	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00
ZILP220 220	0.0	0.00	0.0	0.00	0.0	0.00		
FROM 9876 0	0.0	0.00	1625.1	-84.02	0.0	0.00	0.0	0.00
CHER220 220	1625.1	-84.02	1625.1	155.98	1625.1	35.98		

SUM OF CONTRIBUTIONS INTO BUS 380 [KRASNOD 220]:

380	0.0	0.00	17734.1	-82.33	0.0	0.00	0.0	0.00
KRASNOD 220	17734.1	-82.33	17734.1	157.67	17734.1	37.67		

SHUNT + LOAD CURRENT AT BUS 380 [KRASNOD 220]:

380	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00
KRASNOD 220	0.0	0.00	0.0	0.00	0.0	0.00		

FAULT CURRENT AT BUS 380 [KRASNOD 220]:

380		0.0	0.00	17734.1	-82.33	0.0	0.00	0.0	0.00
KRASNOD	220	17734.1	-82.33	17734.1	157.67	17734.1	37.67		

UNBALANCES APPLIED:

LINE TO GROUND FAULT AT BUS 379 [18.0] PHASE 1
L-G Z = 0.0000 0.0000

LINE TO LINE TO GROUND FAULT AT BUS 379 [18.0] EXCLUDED PHASE 1
L-L Z = 0.0000 0.0000 L-G Z = 0.0000 0.0000

SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

BUS	NAME	BSKV	ZERO		POSITIVE		NEGATIVE	
379		18.0	0.00000	0.04074	0.00056	0.01883	0.00056	0.01883

1 PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E FRI OCT 06, 1995 16:12
MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-0)

THREE PHASE FAULT AT BUS 379 [18.0]:

SEQUENCE PHASE		RE(V0) RE(VA)	IM(V0) IM(VA)	RE(V+) RE(VB)	IM(V+) IM(VB)	RE(V-) RE(VC)	IM(V-) IM(VC)	RE(3V0)	IM(3V0)
379	(P.U.)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	18.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		

SEQUENCE PHASE	RE(I0) RE(IA)	IM(I0) IM(IA)	RE(I+) RE(IB)	IM(I+) IM(IB)	RE(I-) RE(IC)	IM(I-) IM(IC)	RE(3I0)	IM(3I0)
MACHINE 1	0.0000	0.0000	2.3834	-9.2331	0.0000	0.0000	0.0000	0.0000
	2.3834	-9.2331	-9.1878	2.5525	6.8044	6.6806		
MACHINE 2	0.0000	0.0000	2.3834	-9.2331	0.0000	0.0000	0.0000	0.0000
	2.3834	-9.2331	-9.1878	2.5525	6.8044	6.6806		
MACHINE 3	0.0000	0.0000	2.3834	-9.2331	0.0000	0.0000	0.0000	0.0000
	2.3834	-9.2331	-9.1878	2.5525	6.8044	6.6806		
FROM 339 1	0.0000	0.0000	0.8179	-29.7881	0.0000	0.0000	0.0000	0.0000
KRASNOD 500	0.8179	-29.7881	-26.2061	14.1857	25.3883	15.6023		

SUM OF CONTRIBUTIONS INTO BUS 379 [18.0]:

379		0.0000	0.0000	7.9680	-57.4873	0.0000	0.0000	0.0000	0.0000
	18.0	7.9680	-57.4873	-53.7695	21.8431	45.8014	35.6442		

SHUNT + LOAD CURRENT AT BUS 379 [18.0]:

379		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	18.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		

FAULT CURRENT AT BUS 379 [18.0]:

379		0.0000	0.0000	7.9680	-57.4873	0.0000	0.0000	0.0000	0.0000
	18.0	7.9680	-57.4873	-53.7695	21.8431	45.8014	35.6442		

UNBALANCES APPLIED:

LINE TO GROUND FAULT AT BUS 381 [18.0] PHASE 1
L-G Z = 0.0000 0.0000

LINE TO LINE TO GROUND FAULT AT BUS 381 [18.0] EXCLUDED PHASE 1
L-L Z = 0.0000 0.0000 L-G Z = 0.0000 0.0000

SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

BUS	NAME	BSKV	ZERO		POSITIVE		NEGATIVE	
381		18.0	0.00000	0.04074	0.00088	0.02026	0.00088	0.02026

1 PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E FRI OCT 06, 1995 16:12
MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-0)

THREE PHASE FAULT AT BUS 381 [18.0]:

SEQUENCE PHASE	RE(V0) RE(VA)	IM(V0) IM(VA)	RE(V+) RE(VB)	IM(V+) IM(VB)	RE(V-) RE(VC)	IM(V-) IM(VC)	RE(3V0)	IM(3V0)
381 (P.U.)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
18.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		

SEQUENCE PHASE	RE(I0) RE(IA)	IM(I0) IM(IA)	RE(I+) RE(IB)	IM(I+) IM(IB)	RE(I-) RE(IC)	IM(I-) IM(IC)	RE(3I0)	IM(3I0)
MACHINE 1	0.0000	0.0000	2.2109	-8.9820	0.0000	0.0000	0.0000	0.0000
	2.2109	-8.9820	-8.8841	2.5763	6.6732	6.4058		
MACHINE 2	0.0000	0.0000	2.2109	-8.9820	0.0000	0.0000	0.0000	0.0000
	2.2109	-8.9820	-8.8841	2.5763	6.6732	6.4058		
MACHINE 3	0.0000	0.0000	2.2109	-8.9820	0.0000	0.0000	0.0000	0.0000
	2.2109	-8.9820	-8.8841	2.5763	6.6732	6.4058		
FROM 380 1	0.0000	0.0000	0.7703	-26.7968	0.0000	0.0000	0.0000	0.0000
KRASNOD 220	0.7703	-26.7968	-23.5919	12.7313	22.8216	14.0655		

SUM OF CONTRIBUTIONS INTO BUS 381 [18.0]:

381	0.0000	0.0000	7.4032	-53.7429	0.0000	0.0000	0.0000	0.0000
18.0	7.4032	-53.7429	-50.2443	20.4601	42.8411	33.2828		

SHUNT + LOAD CURRENT AT BUS 381 [18.0]:

381	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
18.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		

FAULT CURRENT AT BUS 381 [18.0]:

381	0.0000	0.0000	7.4032	-53.7429	0.0000	0.0000	0.0000	0.0000
18.0	7.4032	-53.7429	-50.2443	20.4601	42.8411	33.2828		

UNBALANCES APPLIED:

LINE TO GROUND FAULT AT BUS 8765 [ZILP220 220] PHASE 1
L-G Z = 0.0000 0.0000

LINE TO LINE TO GROUND FAULT AT BUS 8765 [ZILP220 220] EXCLUDED PHASE 1
L-L Z = 0.0000 0.0000 L-G Z = 0.0000 0.0000

SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

BUS	NAME	BSKV	ZERO		POSITIVE		NEGATIVE	
8765	ZILP220	220	0.00000	*********	0.00436	0.02338	0.00436	0.02338

THREE PHASE FAULT AT BUS 8765 [ZILP220 220]:

SEQUENCE PHASE	/V0/ /VA/	AN(V0) AN(VA)	/V+/ /VB/	AN(V+) AN(VB)	/V-/ /VC/	AN(V-) AN(VC)	/3V0/	AN(3V0)
8765 (KV L-G)	7.939	-90.00	0.194	11.92	0.194	11.92	23.816	-90.00
ZILP220 220	7.868	-87.24	7.981	-91.36	7.981	-91.36		

SEQUENCE PHASE	/I0/ /IA/	AN(I0) AN(IA)	/I+/ /IB/	AN(I+) AN(IB)	/I-/ /IC/	AN(I-) AN(IC)	/3I0/	AN(3I0)
FROM 380 1	0.0	0.00	5961.2	-78.06	8.3	111.42	0.0	0.00
KRASNOD 220	5953.0	-78.08	5964.1	162.01	5966.4	41.87		
FROM 380 2	0.0	0.00	5961.2	-78.06	8.3	111.42	0.0	0.00
KRASNOD 220	5953.0	-78.08	5964.1	162.01	5966.4	41.87		

SUM OF CONTRIBUTIONS INTO BUS 8765 [ZILP220 220]:

8765	0.0	0.00	11922.3	-78.06	16.6	111.42	0.0	0.00
ZILP220 220	11905.9	-78.08	11928.2	162.01	11932.9	41.87		

CONTRIBUTIONS EQUIVALENT POSITIVE SEQUENCE ADMITTANCE 8.4695**********

SHUNT + LOAD CURRENT AT BUS 8765 [ZILP220 220]:

8765	0.0	0.00	0.4	-9.88	0.4	-9.88	0.0	0.00
ZILP220 220	0.7	-9.88	0.4	170.11	0.4	170.12		

FAULT CURRENT AT BUS 8765 [ZILP220 220]:

8765	0.0	0.00	11922.2	-78.07	16.8	112.49	0.0	0.00
ZILP220 220	11905.6	-78.08	11927.8	162.01	11933.1	41.87		

POSITIVE SEQUENCE EQUIVALENT FAULT ADMITTANCE 7.6149**********

1 PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E FRI OCT 06, 1995 16:04
MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-0)

UNBALANCES APPLIED:

LINE TO GROUND FAULT AT BUS 9876 [CHER220 220] PHASE 1
L-G Z = 0.0000 0.0000

LINE TO LINE TO GROUND FAULT AT BUS 9876 [CHER220 220] EXCLUDED PHASE 1
L-L Z = 0.0000 0.0000 L-G Z = 0.0000 0.0000

SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

BUS	NAME	BSKV	ZERO		POSITIVE		NEGATIVE	
9876	CHER220	220	0.00000	*********	0.00828	0.03595	0.00828	0.03595

1 PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E FRI OCT 06, 1995 16:04
MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-0)

THREE PHASE FAULT AT BUS 9876 [CHER220 220]:

SEQUENCE PHASE	/V0/ /VA/	AN(V0) AN(VA)	/V+/ /VB/	AN(V+) AN(VB)	/V-/ /VC/	AN(V-) AN(VC)	/3V0/	AN(3V0)
9876 (KV L-G)	0.000	0.00	2.995	10.29	2.995	10.29	0.000	0.00
CHER220 220	5.991	10.29	2.995	-169.71	2.995	-169.71		

SEQUENCE PHASE	/I0/ /IA/	AN(I0) AN(IA)	/I+/ /IB/	AN(I+) AN(IB)	/I-/ /IC/	AN(I-) AN(IC)	/3I0/	AN(3I0)
FROM 346 0	0.0	0.00	3699.2	-82.45	83.6	112.18	0.0	0.00
220	3618.4	-82.79	3722.2	158.79	3758.4	36.64		
FROM 380 0	0.0	0.00	3687.3	-76.29	80.9	110.90	0.0	0.00
KRASNOD 220	3607.1	-76.45	3719.4	164.86	3736.7	42.72		

SUM OF CONTRIBUTIONS INTO BUS 9876 [CHER220 220]:

9876	0.0	0.00	7375.8	-79.38	164.4	111.55	0.0	0.00
CHER220 220	7214.4	-79.62	7431.1	161.82	7484.5	39.67		

CONTRIBUTIONS EQUIVALENT POSITIVE SEQUENCE ADMITTANCE 6.9707-1191.7661

SHUNT + LOAD CURRENT AT BUS 9876 [CHER220 220]:

9876	0.0	0.00	5.9	-11.51	5.9	-11.51	0.0	0.00
CHER220 220	11.9	-11.51	5.9	168.49	5.9	168.49		

FAULT CURRENT AT BUS 9876 [CHER220 220]:

9876	0.0	0.00	7373.6	-79.42	167.7	113.25	0.0	0.00
CHER220 220	7210.0	-79.71	7425.3	161.82	7488.3	39.64		

POSITIVE SEQUENCE EQUIVALENT FAULT ADMITTANCE 6.0801-1191.4098

591

UNBALANCES APPLIED:

LINE TO GROUND FAULT AT BUS 337 [KURGAN 220] PHASE 1
L-G Z = 0.0000 0.0000

LINE TO LINE TO GROUND FAULT AT BUS 337 [KURGAN 220] EXCLUDED PHASE 1
L-L Z = 0.0000 0.0000 L-G Z = 0.0000 0.0000

SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

BUS	NAME	BSKV	ZERO		POSITIVE		NEGATIVE	
337	KURGAN	220	0.00000	*********	0.00338	0.02054	0.00338	0.02054

THREE PHASE FAULT AT BUS 337 [KURGAN 220]:

SEQUENCE PHASE	/V0/ /VA/	AN(V0) AN(VA)	/V+/ /VB/	AN(V+) AN(VB)	/V-/ /VC/	AN(V-) AN(VC)	/3V0/	AN(3V0)
337 (KV L-G)	16.001	-172.88	9.091	7.48	9.091	7.48	48.002	-172.88
KURGAN 220	2.183	10.05	25.091	-172.75	25.091	-172.75		

SEQUENCE PHASE	/I0/ /IA/	AN(I0) AN(IA)	/I+/ /IB/	AN(I+) AN(IB)	/I-/ /IC/	AN(I-) AN(IC)	/3I0/	AN(3I0)
FROM 346 1	0.0	0.00	1695.4	-83.80	121.0	109.65	0.0	0.00
220	1577.9	-84.83	1733.7	160.03	1780.8	33.37		
FROM 346 2	0.0	0.00	1695.4	-83.80	121.0	109.65	0.0	0.00
220	1577.9	-84.83	1733.7	160.03	1780.8	33.37		
FROM 347 1	0.0	0.00	1984.7	-85.93	146.7	103.93	0.0	0.00
220	1840.4	-86.71	2039.9	157.94	2081.8	30.97		
FROM 347 2	0.0	0.00	1984.7	-85.93	146.7	103.93	0.0	0.00
220	1840.4	-86.71	2039.9	157.94	2081.8	30.97		
FROM 380 1	0.0	0.00	2620.5	-77.45	181.7	106.50	0.0	0.00
KRASNOD 220	2439.3	-77.75	2705.2	166.01	2726.1	39.38		
FROM 380 2	0.0	0.00	2620.5	-77.45	181.7	106.50	0.0	0.00
KRASNOD 220	2439.3	-77.75	2705.2	166.01	2726.1	39.38		

SUM OF CONTRIBUTIONS INTO BUS 337 [KURGAN 220]:

337	0.0	0.00	12573.8	-81.83	898.1	106.51	0.0	0.00
KURGAN 220	11685.9	-82.47	12932.2	161.87	13149.8	35.10		

CONTRIBUTIONS EQUIVALENT POSITIVE SEQUENCE ADMITTANCE 8.0791 -669.4065

SHUNT + LOAD CURRENT AT BUS 337 [KURGAN 220]:

337	0.0	0.00	6.3	-23.74	6.3	-23.74	0.0	0.00
KURGAN 220	12.5	-23.74	6.3	156.26	6.3	156.26		

FAULT CURRENT AT BUS 337 [KURGAN 220]:

337	0.0	0.00	12570.5	-81.86	902.2	106.81	0.0	0.00
KURGAN 220	11679.4	-82.52	12926.0	161.87	13153.1	35.07		

POSITIVE SEQUENCE EQUIVALENT FAULT ADMITTANCE 7.7938 -669.2336

1 PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E FRI OCT 06, 1995 16:06
MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-0)

UNBALANCES APPLIED:

LINE TO GROUND FAULT AT BUS 333 [ZELENCHU 500] PHASE 1
L-G Z = 0.0000 0.0000

LINE TO LINE TO GROUND FAULT AT BUS 333 [ZELENCHU 500] EXCLUDED PHASE 1
L-L Z = 0.0000 0.0000 L-G Z = 0.0000 0.0000

SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

BUS	NAME	BSKV	ZERO		POSITIVE		NEGATIVE	
333	ZELENCHU	500	0.00000	0.20667	0.00160	0.01650	0.00160	0.01650

1 PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E FRI OCT 06, 1995 16:06
MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-0)

THREE PHASE FAULT AT BUS 333 [ZELENCHU 500]:

SEQUENCE PHASE	/V0/ /VA/	AN(V0) AN(VA)	/V+/ /VB/	AN(V+) AN(VB)	/V-/ /VC/	AN(V-) AN(VC)	/3V0/	AN(3V0)
333 (KV L-G)	0.000	0.00	0.000	0.00	0.000	0.00	0.000	0.00
ZELENCHU 500	0.000	0.00	0.000	0.00	0.000	0.00		

SEQUENCE PHASE	/I0/ /IA/	AN(I0) AN(IA)	/I+/ /IB/	AN(I+) AN(IB)	/I-/ /IC/	AN(I-) AN(IC)	/3I0/	AN(3I0)
MACHINE 1	0.0	0.00	589.8	-79.07	0.0	0.00	0.0	0.00
	589.8	-79.07	589.8	160.93	589.8	40.93		
FROM 101 0	0.0	0.00	3283.4	-82.05	0.0	0.00	0.0	0.00
INGURI 500	3283.4	-82.05	3283.4	157.95	3283.4	37.95		
FROM 339 0	0.0	0.00	3396.3	-82.79	0.0	0.00	0.0	0.00
KRASNOD 500	3396.3	-82.79	3396.3	157.21	3396.3	37.21		

SUM OF CONTRIBUTIONS INTO BUS 333 [ZELENCHU 500]:

333	0.0	0.00	7268.4	-82.15	0.0	0.00	0.0	0.00
ZELENCHU 500	7268.4	-82.15	7268.4	157.85	7268.4	37.85		

SHUNT + LOAD CURRENT AT BUS 333 [ZELENCHU 500]:

333	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00
ZELENCHU 500	0.0	0.00	0.0	0.00	0.0	0.00		

FAULT CURRENT AT BUS 333 [ZELENCHU 500]:

333	0.0	0.00	7268.4	-82.15	0.0	0.00	0.0	0.00
ZELENCHU 500	7268.4	-82.15	7268.4	157.85	7268.4	37.85		

UNBALANCES APPLIED:

LINE TO GROUND FAULT AT BUS 347 [220] PHASE 1
L-G Z = 0.0000 0.0000

LINE TO LINE TO GROUND FAULT AT BUS 347 [220] EXCLUDED PHASE 1
L-L Z = 0.0000 0.0000 L-G Z = 0.0000 0.0000

SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

BUS	NAME	BSKV	ZERO		POSITIVE		NEGATIVE	
347		220	0.00000	*********	0.00251	0.02278	0.00251	0.02278

1 PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E FRI OCT 06, 1995 16:07
MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-0)

THREE PHASE FAULT AT BUS 347 [220]:

SEQUENCE PHASE	/V0/ /VA/	AN(V0) AN(VA)	/V+/ /VB/	AN(V+) AN(VB)	/V-/ /VC/	AN(V-) AN(VC)	/3V0/	AN(3V0)
347 (KV L-G)	16.001	-7.13	2.061	5.17	2.061	5.17	48.002	-7.13
220	20.048	-4.62	13.993	-8.92	13.993	-8.92		

SEQUENCE PHASE	/I0/ /IA/	AN(I0) AN(IA)	/I+/ /IB/	AN(I+) AN(IB)	/I-/ /IC/	AN(I-) AN(IC)	/3I0/	AN(3I0)
FROM 320 0	0.0	0.00	6901.5	-89.26	110.2	97.68	0.0	0.00
ARMAVIR 330	6792.1	-89.37	6945.4	151.58	6968.3	30.02		
FROM 337 1	0.0	0.00	2520.3	-78.53	38.1	106.94	0.0	0.00
KURGAN 220	2482.3	-78.62	2536.3	162.25	2542.6	40.77		
FROM 337 2	0.0	0.00	2520.3	-78.53	38.1	106.94	0.0	0.00
KURGAN 220	2482.3	-78.62	2536.3	162.25	2542.6	40.77		

SUM OF CONTRIBUTIONS INTO BUS 347 [220]:

347	0.0	0.00	11891.1	-84.73	185.8	101.46	0.0	0.00
220	11706.4	-84.83	11967.3	156.08	12001.7	34.55		

CONTRIBUTIONS EQUIVALENT POSITIVE SEQUENCE ADMITTANCE 4.7828-2791.8687

FAULT CURRENT AT BUS 347 [220]:

347	0.0	0.00	11891.1	-84.73	185.8	101.46	0.0	0.00
220	11706.4	-84.83	11967.3	156.08	12001.7	34.55		

POSITIVE SEQUENCE EQUIVALENT FAULT ADMITTANCE 4.7828-2791.8687

UNBALANCES APPLIED:

LINE TO GROUND FAULT AT BUS 320 [ARMAVIR 330] PHASE 1
L-G Z = 0.0000 0.0000

LINE TO LINE TO GROUND FAULT AT BUS 320 [ARMAVIR 330] EXCLUDED PHASE 1
L-L Z = 0.0000 0.0000 L-G Z = 0.0000 0.0000

SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

BUS	NAME	BSKV	ZERO		POSITIVE		NEGATIVE	
320	ARMAVIR	330	0.00000	0.88571	0.00146	0.00945	0.00146	0.00945

1 PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E FRI OCT 06, 1995 16:07
MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-0)

THREE PHASE FAULT AT BUS 320 [ARMAVIR 330]:

SEQUENCE PHASE	/V0/ /VA/	AN(V0) AN(VA)	/V+/ /VB/	AN(V+) AN(VB)	/V-/ /VC/	AN(V-) AN(VC)	/3V0/	AN(3V0)
320 (KV L-G)	0.001	0.00	0.000	0.00	0.000	0.00	0.002	0.00
ARMAVIR 330	0.001	-0.08	0.001	-0.77	0.001	0.86		

SEQUENCE PHASE	/I0/ /IA/	AN(I0) AN(IA)	/I+/ /IB/	AN(I+) AN(IB)	/I-/ /IC/	AN(I-) AN(IC)	/3I0/	AN(3I0)
MACHINE 1	0.0	0.00	243.2	-91.08	0.0	0.00	0.0	0.00
	243.2	-91.08	243.2	148.92	243.2	28.92		
FROM 304 0	0.0	0.00	2513.7	-89.89	0.0	0.00	0.0	0.00
330	2513.7	-89.89	2513.7	150.11	2513.7	30.11		
FROM 312 1	0.0	0.00	9269.5	-80.53	0.0	0.00	0.0	0.00
330	9269.5	-80.53	9269.5	159.47	9269.5	39.47		
FROM 319 0	0.0	0.00	4766.5	-83.01	0.0	0.00	0.0	0.00
HEBHOM. 330	4766.5	-83.01	4766.5	156.99	4766.5	36.99		
FROM 347 0	0.0	0.00	2151.3	-82.02	0.0	0.00	0.0	0.00
220	2151.3	-82.02	2151.3	157.98	2151.3	37.98		

SUM OF CONTRIBUTIONS INTO BUS 320 [ARMAVIR 330]:

320	0.0	0.00	18915.0	-82.70	0.0	0.00	0.0	0.00
ARMAVIR 330	18915.0	-82.70	18915.0	157.30	18915.0	37.30		

SHUNT + LOAD CURRENT AT BUS 320 [ARMAVIR 330]:

320	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00
ARMAVIR 330	0.0	0.00	0.0	0.00	0.0	0.00		

FAULT CURRENT AT BUS 320 [ARMAVIR 330]:

320	0.0	0.00	18915.0	-82.70	0.0	0.00	0.0	0.00
ARMAVIR 330	18915.0	-82.70	18915.0	157.30	18915.0	37.30		

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1 PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E FRI OCT 06, 1995 16:05
MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-0)

UNBALANCES APPLIED:

LINE TO GROUND FAULT AT BUS 321 [TZENTRAL 500] PHASE 1
L-G Z = 0.0000 0.0000

LINE TO LINE TO GROUND FAULT AT BUS 321 [TZENTRAL 500] EXCLUDED PHASE 1
L-L Z = 0.0000 0.0000 L-G Z = 0.0000 0.0000

SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

BUS	NAME	BSKV	ZERO		POSITIVE		NEGATIVE	
321	TZENTRAL	500	0.00000	*********	0.00145	0.01161	0.00145	0.01161

1 PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E FRI OCT 06, 1995 16:05
MOSTOVSKAYA PROJECT, PROJECT CASE (2-0-0)

THREE PHASE FAULT AT BUS 321 [TZENTRAL 500]:

SEQUENCE PHASE	/V0/ /VA/	AN(V0) AN(VA)	/V+/ /VB/	AN(V+) AN(VB)	/V-/ /VC/	AN(V-) AN(VC)	/3V0/	AN(3V0)
321 (KV L-G)	144.338	180.00	151.679	-167.04	151.679	-167.04	433.013	180.00
TZENTRAL 500	445.198	-171.21	34.188	84.16	34.188	84.16		

SEQUENCE PHASE	/I0/ /IA/	AN(I0) AN(IA)	/I+/ /IB/	AN(I+) AN(IB)	/I-/ /IC/	AN(I-) AN(IC)	/3I0/	AN(3I0)
FROM 311 0	0.0	0.00	4935.9	-79.47	1625.0	-70.98	0.0	0.00
STAVROP 500	6547.6	-77.37	4595.7	141.33	4125.6	58.49		
FROM 339 0	0.0	0.00	4517.5	-76.91	1414.0	-72.18	0.0	0.00
KRASNOD 500	5927.8	-75.78	4117.5	145.00	3889.6	60.47		
FROM 346 0	0.0	0.00	4396.6	-80.76	1565.9	-67.22	0.0	0.00
220	5930.3	-77.22	4228.5	138.43	3506.7	58.12		
FROM 395 0	0.0	0.00	1192.3	-84.58	385.5	-64.80	0.0	0.00
SOCHI 500	1560.6	-79.78	1186.2	136.77	931.8	50.92		

SUM OF CONTRIBUTIONS INTO BUS 321 [TZENTRAL 500]:

321	0.0	0.00	15032.0	-79.48	4985.8	-69.67	0.0	0.00
TZENTRAL 500	19962.9	-77.04	14110.5	141.15	12443.2	58.44		

CONTRIBUTIONS EQUIVALENT POSITIVE SEQUENCE ADMITTANCE 10.5518 247.5350

SHUNT + LOAD CURRENT AT BUS 321 [TZENTRAL 500]:

321	0.0	0.00	200.2	102.96	200.2	102.96	0.0	0.00
TZENTRAL 500	400.4	102.96	200.2	-77.04	200.2	-77.04		

FAULT CURRENT AT BUS 321 [TZENTRAL 500]:

321	0.0	0.00	15232.0	-79.45	5184.5	-69.95	0.0	0.00
TZENTRAL 500	20363.3	-77.04	14268.4	140.65	12586.8	59.08		

POSITIVE SEQUENCE EQUIVALENT FAULT ADMITTANCE 10.5518 250.8351

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UNBALANCES APPLIED:

LINE TO GROUND FAULT AT BUS 346 [220] PHASE 1
L-G Z = 0.0000 0.0000

LINE TO LINE TO GROUND FAULT AT BUS 346 [220] EXCLUDED PHASE 1
L-L Z = 0.0000 0.0000 L-G Z = 0.0000 0.0000

SEQUENCE THEVENIN IMPEDANCES AT FAULTED BUSES:

BUS	NAME	BSKV	ZERO		POSITIVE		NEGATIVE	
346		220	0.00000	0.40789	0.00244	0.01402	0.00244	0.01402

THREE PHASE FAULT AT BUS 346 [220]:

SEQUENCE PHASE	/V0/ /VA/	AN(V0) AN(VA)	/V+/ /VB/	AN(V+) AN(VB)	/V-/ /VC/	AN(V-) AN(VC)	/3V0/	AN(3V0)
346 (KV L-G)	0.000	0.00	0.000	0.00	0.000	0.00	0.000	0.00
220	0.000	0.00	0.000	0.00	0.000	0.00		

SEQUENCE PHASE	/I0/ /IA/	AN(I0) AN(IA)	/I+/ /IB/	AN(I+) AN(IB)	/I-/ /IC/	AN(I-) AN(IC)	/3I0/	AN(3I0)
MACHINE 1	0.0	0.00	807.4	-91.74	0.0	0.00	0.0	0.00
	807.4	-91.74	807.4	148.26	807.4	28.26		
FROM 321 0	0.0	0.00	8237.8	-85.41	0.0	0.00	0.0	0.00
TZENTRAL 500	8237.8	-85.41	8237.8	154.59	8237.8	34.59		
FROM 336 0	0.0	0.00	2231.8	-86.90	0.0	0.00	0.0	0.00
AFIPSKAY 220	2231.8	-86.90	2231.8	153.10	2231.8	33.10		
FROM 337 1	0.0	0.00	1405.3	-76.86	0.0	0.00	0.0	0.00
KURGAN 220	1405.3	-76.86	1405.3	163.14	1405.3	43.14		
FROM 337 2	0.0	0.00	1405.3	-76.86	0.0	0.00	0.0	0.00
KURGAN 220	1405.3	-76.86	1405.3	163.14	1405.3	43.14		
FROM 338 0	0.0	0.00	1253.2	-86.62	0.0	0.00	0.0	0.00
SHEPSI 220	1253.2	-86.62	1253.2	153.38	1253.2	33.38		
FROM 344 0	0.0	0.00	2721.8	-83.67	0.0	0.00	0.0	0.00
KRASOD 220	2721.8	-83.67	2721.8	156.33	2721.8	36.33		
FROM 9876 0	0.0	0.00	1586.6	-74.96	0.0	0.00	0.0	0.00
CHER220 220	1586.6	-74.96	1586.6	165.04	1586.6	45.04		

SUM OF CONTRIBUTIONS INTO BUS 346 [220]:

346	0.0	0.00	19594.2	-83.61	0.0	0.00	0.0	0.00
220	19594.2	-83.61	19594.2	156.39	19594.2	36.39		

SHUNT + LOAD CURRENT AT BUS 346 [220]:

346	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00
220	0.0	0.00	0.0	0.00	0.0	0.00		

FAULT CURRENT AT BUS 346 [220]:

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346		0.0	0.00	19594.2	-83.61	0.0	0.00	0.0	0.00
	220	19594.2	-83.61	19594.2	156.39	19594.2	36.39		

APPENDIX J

FINANCE AND ACCOUNTING RECOMMENDATIONS

APPENDIX J

FINANCE AND ACCOUNTING RECOMMENDATIONS KRASNODAR POWER PROJECT

I. Develop a Statement of Accounting Principles and Policies together with procedures to implement. The Statement of Principles should include such accounting concepts as Cash or Accrual Accounting, Capital vs. Expense Guidelines for plant addition or betterments, Consumable Inventories Expensing and Pricing, Depreciation Policies, etc. An alternative course would be the adoption of Accounting Standards as utilized in the investor owned utility industry of the United States.

The Statement of Accounting Principles and Policies should be initiated by the Kuban GRES Executive and Financial Management and approved by its Board of Directors. It is of paramount importance that the Investors (Equity and Debt Holders) Requirements for Financial Information is met when defining these policies together with government regulatory needs.

II. Adopt Account and Management Information Systems. It is recommended that the Kuban GRES have a Financial Reporting System as well as a Managerial Accounting Reporting System. The Financial Accounting System is to provide the basis for monthly and year to date statements of Income, Balance Sheets, and statements of Cash Flow. The Management Accounting System should be actively cost based and report expenses in detail to each level of the management hierarchy. The activities to be costed and the kinds of expenses are to reflect the manger's need to know in exercising his or hers assigned mission. Again reporting should be for monthly and year to date results. Budgets are to be prepared on a monthly and annual basis consistent with the accounts utilized in the reporting systems. Operating and Maintenance and Capital Expenditure budgets are necessary.

III. Develop Chart of Accounts for Kuban GRES. The accounts are to be reflective of and consistent with the accounting system adopted. The account numbering scheme is to permit expansion of informational fields providing for types and kind of expenses associated with a responsible manager. Any other special cost or accumulation or identification is to be provided for within the account numbering scheme.

IV. The Construction Activities of Kuban GRES are to be accounted for on a project basis. Each construction project will be by a separate "work order" identified with its own unique account number where direct and indirect costs are accumulated. These work orders will provide the cost basis for addition to or retirement of Kuban GRES plant assets. Monthly and annual reports of plant construction cost are to be prepared showing project's estimated cost, cost to date, and estimates of project completion date.

V. Accounting for Power Plant Construction Cost. Prior to the start of plant construction, a chart of construction accounts is to be adopted. These accounts will provide for cost accumulation

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at the construction activity level and by plant assets. These accounts will provide a cost basis for depreciation of assets having varying service lives on the books of the Kuban GRES as well as separate the depreciable and non-depreciable plant costs. If the Kuban GRES is not responsible for the accounting during the plant construction phase, the project construction contract is to reflect the desired level of accounting by assets for the project and such allocation of costs by assets turned over to the owners on completion of the project.

VI. All construction contract and purchase, payments for labor, etc., shall include an audit clause permitting the owners or owners' designee to an independent audit of all expenditures. This clause should include provision for unrestricted access to all construction documents, work papers, canceled checks, etc.

VII. Implement procedures manuals to instruct all users and effected employees in the use of the accounting and management systems. Also, at this time employee training sessions are to be conducted on the use of the systems.

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Krasnodar Power Project
Minimal Requirements of Internal Control System

- An Internal Audit Staff function reporting to Senior Financial Management of the Kuban GRES with indirect reporting to the President and Board of Directors. The Audit Staff is to have both Financial & Operations audit responsibility.

- The Board of Directors shall have an Audit Committee. The Audit Committee is to have an annual meeting with the Audit Staff at which time a schedule of audits for the next annual period shall be reviewed, along with previous years' actual audit results.

- A Chart of Accounts for financial reporting purposes, together with a written accounting procedures manual distributed to appropriate employees.

- Establish and document approval levels for purchasing or contracting materials, services, and labor. The amount of commitment is to be the guideline in determining the approval level required. The President and Board of Directors shall approve on recommendation of Senior Financial Management.

- Approval level for disbursements of funds should be established and documented. Check signing approval level is to be considered in establishing this control.

- The number of employees and manner of compensation shall be approved by the President and Board of Directors. New employee positions are to require President's approval.

- In the disbursement of funds and handling of cash, the internal control concept of separation of responsibilities shall be adhered to.

- Fuel, material and supply inventory shall be subject to periodic audits by comparing book quantities with quantities on hand.

- Operation policies and procedures should be written by major segments of the Kuban GRES organization. These shall be approved by the President and the related member of the Senior Management.

- Monthly reports of Financial Results and Operations Statistics are to be prepared for the Board of Directors and Senior Management. These reports should include management's discussion and analysis of the operating results.

- A conflict of interest policy shall be established for employees who have responsibility for purchasing and contracting with vendors and contractors.

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Krasnodar Kuban GRES
Financial Reporting System
Representative Generic Chart of Accounts

A/C NO.	Account Description Balance Sheet Accounts Current Assets
101	Cash This account shall include the amount of cash on hand and in banks.
102	Cash - Special Deposits This account shall include cash advances to employees as petty cash or working funds.
103	Cash Advances This account shall include 1
104	Temporary Cash Investments This account shall include investments in marketable securities held for less than one year
106	Notes Receivable This account shall include investments in marketable securities held for less than one year.
107	Customer Accounts Receivable This account shall include amounts due from customers for utility service.
108	Accounts Receivable Other Amounts due from non utility activities.
109	Accumulated Provision for Uncollectible Accounts - Credit Amounts accrued to provide for estimates of uncollectible accounts
111	Fuel Inventory This account shall include the cost of fuel delivered to the plant for generation.

112	Plant Materials & Operating Supplies This account shall include the cost of materials purchased for use in the utility for construction operation and maintenance including fuel for vehicles.

A/C No.	**Account Description**
113	Other Materials and Supplies This account shall include the cost of materials and supplies held for non-utility purpose.
114	Prepayments prepayment of insurance, rent, taxes, etc.
115	Interest & Dividends Receivable This account shall include accrued interest on temporary investments, deposits, etc.
116	Rents Receivable This account shall include accrued rent on utility property rented to others.
117	Miscellaneous Current & Accrued Assets This account shall include all other current and accrued assets not provided for in other accounts.

Deferred Debits

118	Unamortized Debt Expense Expenses associated with issue or assumption of debt to be amortized over the life of the debt as interest expense.
119	Feasibility Studies This account shall be charged expenses associated with studies for determining the feasibility of utility projects which may or may not be undertaken. If construction results from the study, the amounts shall be capitalized, otherwise expensed.

120	Miscellaneous Deferred Debits This account shall include all debits not elsewhere provided for which are for the purpose of amortization.
A/C No.	**Account Description**
	Plant Assets
201	Land & Land Rights This account shall include the cost of land and land rights used in utility operation.
202	Structures & Improvements This account shall include the cost in place of structures and improvements.
203	Production Plant Equipment This account shall include the cost in place of power plant equipment, including turbines, cooling towers, control systems, mechanical and electrical equipment, HRSG transformers, etc. Supporting detail by items of property shall be maintained by use of sub-accounts.
204	Miscellaneous Plant Equipment This account shall include furniture, computers, trucks, tractors, tools, shop and garage equipment, stores and line equipment, etc. Details to support this account by items of property shall be maintained by use of sub-accounts.
205	Communication Equipment

206	Construction Work in Progress This account shall include cost of power plant and other construction (including direct purchase of assets) with lives of one year or more. Detail shall be maintained by work orders. Amounts shall be transferred to Plant Asset Accounts on project completion.
208	Accumulated Provision For Depreciation of Plant & Equipment This account shall be credited for amounts charged to depreciation expense. At the time of retirement of electric plant, this account shall be charged with the book cost of property retired and the cost of removal. Any salvage values shall be credited to this account. Detail of each retirement shall be by retirement work orders.
210	Non-Utility Property
212	Other Investments

A/C No.	**Account Description**
	Current Liabilities
301	Accounts Payable This account shall include amounts payable within one year.
302	Notes Payable This account shall include face amount of notes due within one year.
304	Customer Deposits This account shall include amounts due customers such as security deposits for electric service.

305	Income Taxes Accrued This account shall include estimates of income taxes payable within the accounting period
306	Other Accrued Taxes This account shall include estimates of tax liabilities other than income - property, VAT taxes, payroll taxes, etc. within the accounting period.
307	Accrued Interest This account shall include interest accrued on debt within the accounting period. The account may use sub-accounts as follows: 307.1 Interest on long term bonds 307.2 Interest on loans long term 307.3 Interest on short term borrowings
308	Miscellaneous Current & Accrued Liabilities This account shall include current liabilities not provided for elsewhere.
	Long Term Liabilities
310	Long Term Debt - Bonds This account shall include the face value of issued and unmatured bonds.
311	Other Long Term Debt This account shall include long term debt other than bonds.

A/C No.	**Account Description**
314	Unamortized Premium on Long Term Debt This account shall include the excess of the cash value received over the face value on the issue on long term debt securities.

315	Unamortized Discount on Long Term Debt - Debit This account shall include the excess of face value of long term debt over the cash value received at time of issuance.
	<u>Owner's Capital</u>
320	Common Stock Issued
322	Preferred Stock Issued
324	Other Capital Contributions This account shall include non cash capital contributions.
326	Retained Earnings
327	Dividends on Owner's Capital This account shall include cash dividends paid to owners.

A/C No.	**Account Description**
	<u>Income Statement Accounts</u> <u>Revenues</u>
401	Operating Revenues This account shall include the total operating revenues. This account is to be maintained in such detail as to classify revenue by customer categories if needed by the use of sub-accounts. For example: 401.1 - Agriculture Sales 401.2 - Sales to Government
403	Non-Utility This account shall include revenues that are non-operating in origin.

Expense Accounts

500 Operation Expense

This account shall include all operation expenses. The account shall provide for sub-accounts as follows:

- 500.1 Supervision & Engineering
- 500.2 Fuel Used in Generation
- 500.5 Generation Expenses - Non Fuel
- 500.6 Operating Supplies - Miscellaneous

502 Maintenance Expenses

This account shall include all plant maintenance expenses. This account shall provide for sub-accounts as follows:

- 502.1 Plant Maintenance Supervision & Engineering
- 502.2 Maintenance of Structures
- 502.3 Maintenance of Generating & Electric Equipment
- 502.5 Maintenance of Other Plant Equipment

505 Purchased Power

This account shall include the cost of electricity purchased for resale.

507 Plant Control & Load Dispatching

This account shall include the expenses (operating & maintenance) of plant control & dispatching of electricity, including communication equipment.

601 Customer Records and Collection Expenses

This account shall include the expenses (operating & maintenance) of labor and materials incurred in customer billing, accounting and collections, including meter reading

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A/C No.	**Account Description**
602	Uncollectible Accounts Expenses This account shall include amounts accrued as estimates of uncollectible accounts.
604	Depreciation Expense This account shall include accrued depreciation of plant assets.
701	Administrative & General Expenses This account shall include all Adm. & General Expenses of the Kuban GRES. This account shall have sub-accounts as follows: 701.2 Salaries of General Office Employees 701.4 Expense Accounts of General Office Employees 701.5 Office Supplies and Expenses 701.6 Outside Services Employed 701.8 Insurance - Property & Liability 701.10 Plant Security Expenses 701.12 Employee Benefits - Health Insurance, Pensions, etc. 701.14 Employee Training & Development 701.16 Research & Development Expense
705	Interest Expense This account shall include interest on outstanding debt issued and may have sub-accounts as follows: 705.1 Interest on long term bonds 705.2 Interest on loans - long term 705.3 Interest on short term borrowing

NOTES: (1) Any of the primary accounts (those designated with a three digit account number) may provide for sub-accounts to permit a detail of cost/expense items as needed.

(2) Sequence of accounts may be rearranged to meet the format of the balance sheet and income statement adopted.

(3) This chart of accounts is intended only as a guide in developing a total financial reporting system.

Krasnodar Kuban GRES
Proposed Expense Analysis Accounts
Management Reporting System

A/C No.	Account Description
	Payroll, Regular Salary
	Payroll, Overtime Salary
	Payroll, Hourly
To Be	Payroll, Hourly Overtime
	Temporary Personnel
	Employee Expense Accounts, Meals and Travel
	Postage
	Freight
Assigned	Employee Clothing & Uniforms
	Vehicle Expenses - Repairs
	Outside Professional Services other than Engineering
	Outside labor contractors
At	Outside Engineering Services
	Office Equipment Repairs
	Environmental Expenses
	Materials & Supplies
	Tools Expense
Time of	Rent Expense
	Utility - Electric
	Utility - Telephone
	Utility - Water/Sewage & Garbage
System	Directors Fees
	Insurance - Medical
	Insurance - Liability
	Insurance - Life
	Insurance - Property
Development	Insurance - workman's compensation
	Vehicle Expenses, Gas & Oil
	Fuel Generation
	Power Purchases
	Computer Equipment & Maintenance Expenses
	Interets Expense
	Uncollectible Accounts

Krasnodar Kuban GRES
Proposed Activities to be Costed
Management Reporting System

A/C No.	Activity Description
To	Plant Security
	Material & Supplies Control Including Tools
Be	Telephone Service
	Vehicle and Garage Service
	Plant Maintenance
Assigned	Plant Operations
	Plant Engineering
	Plant Performance & Testing
	Plant Hazardous Waste Disposal
At	Plant Outage - Scheduled
	Environmental Services
	Administrative Services
Time	Accounting Services - Payroll
	Accounting Services - Accounts Payable
	Accounting Services - Financial & Management Reporting
Of	Accounting Services - Audit Services
	Administrative Services - Purchasing & Contract Administration
	Administrative Services - Computer Services & Systems
	Administrative Services - Employment
	Administrative Services - Office
System	Administrative Services - Public Relations
	Administrative Services - Food Services
	Administrative Services - Mail Room
	Administrative Services - Janitorial & Cleaning
Development	Administrative Services - Employee Training
	Grounds Site Maintenance Including Roads
	Structures Maintenance Other Than Plant