CENTRAL ASIA

REGIONAL ELECTRICITY EXPORT POTENTIAL STUDY

EUROPE AND CENTRAL ASIA REGION
WORLD BANK, WASHINGTON, D.C.

DECEMBER 2004

CENTRAL ASIA

REGIONAL ELECTRICITY EXPORTS POTENTIAL STUDY

December 2004

Europe and Central Asia Region
The World Bank
Washington, D.C.

ACRONYMS AND ABBREVIATIONS

ADB	Asian Development Bank
BCM	billion cubic meters
CACO	Central Asian Cooperation Organization
CAPS	Central Asian Power System
CARs	Central Asian Republics
CHP	Combined Heat and Power
GDP	Gross Domestic Product
GWh	Gigawatt-hour
HV	High Voltage
IGIAs	Inter-Governmental Irrigation Agreements
JBIC	Japan Bank for International Cooperation
KEA	Kazakhstan Electricity Association
kV	Kilovolt
kWh	kilo Watt hour
LV	Low Voltage
MW	Megawatt
RAO UES	Russian Joint-Stock Company Unified Energy System
REC	Regional Electricity Companies
REEPS	Regional Electricity Export Potential Study
RESW	Regional Economic and Sector Work
T&D	Transmission and Distribution
TWh	Terawatt-hour
UNDP	United Nations Development Program
USAID	United State Agency for International Development
WEC	Water Energy Consortium

CENTRAL ASIA
REGIONAL ELECTRICITY EXPORTS POTENTIAL STUDY

Table of Contents

TABLES

FIGURES

BOXES

APPENDIXES (In separate Volume)

ACKNOWLEDGEMENT

This report was prepared by a team led by Raghuveer Sharma and comprised Anil Markandya, Aman Sachdeva, Marat Iskakov, Venkataraman Krishnaswamy, Nikolay Nikolov and Ms. Suzette Pedroso. The work is part of the wider effort by the World Bank, together with its Development Partners, aimed at improved regional cooperation in Central Asia. The team is grateful to: Mamta Murthi, Mangesh Hoskote and Barry Trembath, who peer reviewed the work; to Martin Raiser and Peter Thomson for providing extensive managerial inputs and quality oversight; and to Dennis de Tray (Director, Central Asia Regional Office) and Hossein Razavi (Director, Infrastructure and Energy Services, ECA Region & Director, Infrastructure Economics and Finance), for providing strategic direction to the work. The team is also grateful to Shigeo Katsu, Vice President, Europe and Central Asia (ECA) Region, for the encouragement and engagement at higher levels of client governments on this high profile topic. The team would like to gratefully recognize the contributions of Matthew Buresch, Natalia Charkova, Yukari Tsuchiya, for helping shape the report to its current form.

Central Asia
Regional Electricity Exports Potential Study

EXECUTIVE SUMMARY

Introduction and Key Conclusions

1. The Central Asian Republics[1] are endowed with significant energy related natural resources. However, the distribution of these resources is highly skewed. The Kyrgyz Republic and Tajikistan have abundant hydropower potential but negligible amounts of commercially exploitable fossil fuels. In contrast, Kazakhstan has significant reserves of oil, gas and coal; Uzbekistan has substantial gas reserves as well as some oil and coal and Turkmenistan also has substantial gas reserves together with some oil.

2. During the Soviet Union era these resources were managed on a regional basis. The hydropower resources in the Kyrgyz Republic and Tajikistan were operated primarily as an irrigation system with power generation being secondary. Energy systems were then designed to take account of the location of various energy sources. The result was a system in which energy was exchanged regionally among the various republics. Following the break-up of the Soviet Union, however, the scope of regional exchanges, which were turned into trade in energy, has declined as the individual republics have focused on achieving a greater level of energy self sufficiency.

3. The fossil fuel rich countries, especially Kazakhstan, have been able to leverage their energy resources into a significant volume of energy exports, accessing markets outside Central Asia. In contrast, the Kyrgyz Republic and Tajikistan face energy shortages in the winter and attempts to secure major export markets for their summer hydropower surpluses have not succeeded. The political changes in Afghanistan and sustained economic growth in other neighboring countries such as China, Iran, Pakistan and Russia, however, have raised expectations in the region that opportunities may materialize to export significant amounts of hydropower outside the region. Such an expectation has further raised hopes that support can be obtained for investment in major new generation facilities.

4. The Central Asian republics have asked the World Bank to help identify the potential for electricity exports outside the region and also the impediments that need to be addressed to realize such potential. However, these countries also need to assess how best to meet their own future requirements for electricity. This study, therefore, addresses (i) options for meeting future electricity demand within the region; (ii) the potential scope and location of export markets outside the region and (iii) the prospects for accessing these markets.

[1] Kazakhstan, the Kyrgyz Republic, Tajikistan, Turkmenistan and Uzbekistan.

Key Conclusions

5. The key conclusions of the study may briefly be summarized as follows:

Meeting Regional Demand

i. Annual domestic demand in the Central Asian Republics can be met until about 2020 through the implementation of loss reduction measures, the rehabilitation of existing generation capacity and regional trade at the margin.

ii. Seasonal supply shortages in the winter will persist. While the most cost effective option to meet this shortfall will be to trade at the margin, some new generation will be needed to meet winter demand requirements.

iii. The most attractive new generation options to meet the winter demand requirements are the Talimardjan Thermal Power I Project in Uzbekistan that is largely complete, and the Bishkek II Thermal Power Project in the Kyrgyz Republic, which is partially constructed. The Bishkek II Thermal Power project represents a more cost effective and quicker option to meet the Kyrgyz Republic's future requirements than the Kambarata hydropower projects in the Kyrgyz Republic. These two thermal power plant projects, however, are both dependent upon the availability of gas in Uzbekistan.

iv. In addition, some upgrading of the transmission facilities will be required to facilitate intra-regional trade, including the construction of the North South Line in Kazakhstan, and the reduction of transmission bottlenecks in the southern part of the Central Asian grid.

v. Increased intra-regional trade will provide significant benefits. In order to take full advantage of this, appropriate agreements are required among the countries in the region. In all likelihood these will have to be negotiated on a bi-lateral basis, in which case efforts should be made to ensure that the agreements among the various parties are based on consistent principles. A consistent approach to electricity trade by the various countries would facilitate the development of intra-regional trade. Once agreements are in place they will then have to be carefully managed to ensure the benefits from intra-regional trade are optimized.

Export Markets Outside the Region

i. Afghanistan, Pakistan, Iran, China and Russia are all potential markets for electricity produced in Central Asia. Pakistan and Iran have the added attraction of experiencing their peak demand in the summer when the largest potential electricity surpluses exist in Central Asia.

ii. Access to these markets will particularly benefit the Kyrgyz Republic and Tajikistan since they are the countries with the potential to export significant quantities of electricity. Uzbekistan (and to some extent Kazakhstan), have the potential to export thermal power in the winter and also benefit in their role as prospective transit countries and as potential power traders[2].

iii. Accessing these markets, however, will face a number of constraints. Afghanistan has potential demand but is constrained in its ability to pay for imports. Access to the Pakistan market would involve transit and the associated construction of transmission facilities through Afghanistan. The demand growth in China is centered on the population centers of the East Coast, a considerable distance from Central Asia. Access to the Russian market will require access to the North-South transmission line across Kazakhstan that is under construction and would likely be dependent on RAO UES' interest and willingness to purchase supplies. Supplies to Iran from the Kyrgyz Republic and/or Tajikistan will likely have to compete with supplies from Turkmenistan and will have to transit Afghanistan or Turkmenistan as well as, potentially, Uzbekistan. Moreover, access to export markets would, in many instances, require agreement on power transit among the Central Asian countries themselves.

Potential Access to the Export Markets

i. Major new generation projects in Central Asia will likely only be feasible if there is assured access to export markets outside the region.

ii. Electricity from Central Asia has the potential to compete in cost terms with marginal generation costs in each of the targeted markets outside the region. The cost advantage, however, is not overwhelming and, in several cases, may not be sufficient to overcome security of supply concerns.

iii. The development of export markets for electricity from Central Asia will be very much demand driven. Initially such trade will be limited to seasonally based activity. The more extensive level of trade that would justify the construction of major facilities focused on the export markets will be predicated on the alleviation of supply security concerns on the part of the importing countries, the existence of transmission infrastructure to access the markets and a politically stable environment.

iv. Perceptions of risk among potential investors and importers vary. Western investors currently view the new generation projects as high risk ventures. RAO UES of Russia, on the other hand believes that it can mitigate many of the risks and has expressed particular interest in some of the proposed hydropower projects. RAO UES represents the best opportunity for at least one of the proposed hydropower projects to be implemented in the medium term.

[2] The power trader role could, for example, take the form of importing hydropower and exporting thermal power taking advantage of relative logistics and relative peaking times.

Summary Conclusions

i. Extensive investment in new capacity, for example the proposed Rogun and Talimardjan II projects, will be predicated on the ability to access markets beyond the immediate region and will, therefore, likely be a longer term proposition. A possible scenario for development of Central Asia's electricity generation and trading activity is shown schematically in Figure ES 1 below. This contemplates the phased introduction of measures to make capacity available beginning with the introduction of loss reduction programs to be followed by construction of new capacity needed to meet winter demand within the region (Talimardjan and Bishkek II) and the completion of the transmission link to Russia through Kazakhstan. These activities should be completed in a medium term time frame (up to 10 years). These phases have a relatively high probability of going ahead.

ii. The outlook for implementation of new projects focused on the export markets that could occur in a subsequent phase is too uncertain at this time to justify the commitment of significant resources to the large generation projects[3]. Instead efforts should be focused on (a) developing intra-regional trade; and (b) promoting the introduction of a business climate that will support future investments in generation.

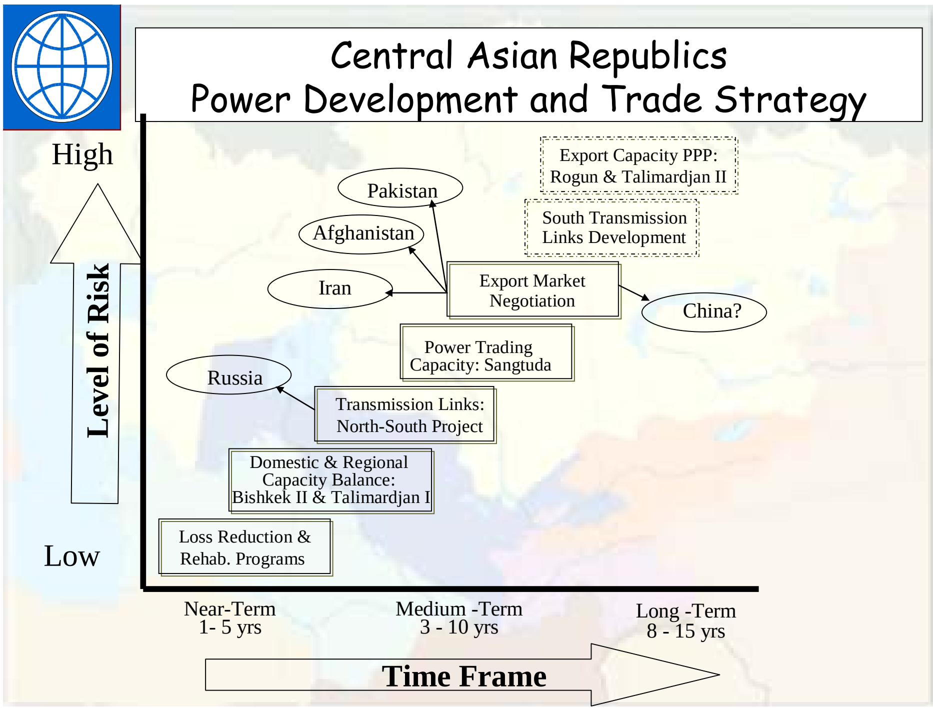


Figure ES 1: Central Asia Republics Power Development and Trade Strategy

[3] The one possible exception to this is Russian involvement in Sangtuda I hydropower project in Tajikistan.

Meeting Regional Demand

6. Table ES1 summarizes the base case[4] gross electricity demand projections for Kazakhstan, the Kyrgyz Republic, Tajikistan and Uzbekistan through 2025.

Table ES 1: Gross Electricity Demand Projections

Country	Forecast Demand (GWh)				
	2003	2010	2015	2020	2025
Kazakhstan	58,944	72,056	84,034	98,367	115,146
The Kyrgyz Republic	12,145	9,222	10,033	11,296	12,719
Tajikistan	16,348	11,267	12,410	13,972	15,731
Uzbekistan	48,691	46,597	51,255	56,589	62,479
All four countries	136,128	139,142	157,731	180,225	206,075

Source: World Bank analysis

7. The projections show that demand will grow during the 2005-2010 timeframe only in Kazakhstan where economic growth is likely to be high, and needed electricity pricing adjustments are minimal. In contrast, demand is projected to decline in the 2005 to 2010 timeframe in the other three countries, a reflection of lower GDP growth forecasts, the impact on demand of substantial increases in real effective tariffs and, in Uzbekistan, the effect of the gasification program of the past few years.

8. Demand growth can be met through a combination of loss reduction measures, rehabilitation of existing generation facilities and the addition of new capacity from projects that have already been identified. Table ES2 summarizes the potential supply increases from these sources.

Table ES 2: Projected Electricity Supply Increments (TWh)

Available Supply 2003*	138.7
Loss Reduction	14.4
Rehabilitation of Existing Facilities	26.9
New Facilities	49.3
Potential Supply Level in 2025	229.3

*Based on 5-year average hydro generation
Source: World Bank analysis

9. Table ES2 indicates that regional demand can be covered until about 2020 without the addition of new generating capacity. Investments would be needed in transmission and distribution facilities in the Kyrgyz Republic and in Tajikistan to reduce technical losses. Investments in Kazakhstan and in Uzbekistan can be justified for generation rehabilitation and to reduce technical losses in transmission and distribution. These investments to upgrade existing facilities generally offer the most cost effective increments of electricity supply in the various

[4] The report considered alternative demand projections and these are addressed in the main body of the text. The selected base case projection is shown in the Executive Summary. The main conclusions of the report, however, will not be significantly affected by the different demand scenarios. What will change is the timing of the requirement for the various increments of new generation capacity, not the overall thrust of the conclusions.

countries. However, seasonal shortages during the winter will remain an issue, while a significant level of net exports would require the addition of new capacity.

10. The region, and more specifically the Kyrgyz Republic and Tajikistan, have several options for dealing with the winter shortages:

i. The Kyrgyz Republic, and, to some extent Tajikistan can potentially operate their hydropower facilities in a power generation mode to increase the availability of electricity in the winter. Such operation, however, carries the risk of downstream flooding during the winter and shortfalls in the availability of water for irrigation in the summer. The 1998 Framework Agreement deals with the issue of the water/energy nexus and sets out terms for operating the hydropower facilities in an irrigation mode (to the benefit of the downstream riparian countries) in exchange for the provision of energy in the winter by the downstream riparian countries. The agreement, however, is not optimal. Even if the agreement were optimized, the region overall would still face a potential shortage in the winter.

ii. The Kyrgyz Republic and Tajikistan both have the potential to generate surplus power in the summer. Iran experiences peak power demand in the summer and may have some surplus generating capacity in the winter, creating the potential to enter into seasonal trading arrangements. In order to enter into such arrangements, however, transit arrangements would have to be negotiated and such arrangements would involve transit of either Afghanistan or Turkmenistan and potentially Uzbekistan.

iii. The construction of some new capacity would also allow the region to meet its winter shortfall. The two projects that would most logically be able to serve this function are the 800 MW Talimardjan Thermal Power Project I in Uzbekistan and the 400 MW Bishkek II Thermal Power Project in the Kyrgyz Republic. The 670 MW Sangtuda I hydropower project in Tajikistan also has the potential to contribute to meeting winter demand.

11. Enhanced intra-regional trade in electricity would also yield benefits:

i. It would allow individual countries to meet future demand at a lower cost than if they were to rely solely on their indigenous resources.

ii. The countries could optimize their cost of supply on a seasonal basis by taking advantage of intra-regional trade opportunities. For example, Kazakhstan and Uzbekistan could both benefit from importing hydro electricity from existing hydropower stations in the summer rather than generate power in their own thermal power stations. This would have the benefits of providing electricity at a lower cost while saving fossil fuel resources and reducing emissions, thereby, creating the potential to benefit from carbon trading.

12. Enhanced intra-regional trade would, however, require some investment in transmission facilities such as the Kazakhstan North-South line (which would also support exports to Russia). This would also require the introduction of a number of institutional reforms including:

i. Negotiation of updated agreements to govern electricity trading between countries. These are likely to be bi-lateral arrangements. However, if these arrangements are all based on a consistent set of principles, they will facilitate increased intra-regional trade. Among the items these agreements need to address are the legal and policy framework for third party access to transmission systems and transmission pricing arrangements.

ii. Introduction of a much greater level of transparency associated with the electricity sectors in the various countries is an important pre-requisite to making informed decisions about electricity trading opportunities.

iii. Careful coordination between the management of electricity resources and the management of water resources will be an important adjunct to effective intra-regional trade in electricity.

The CARs have decided to establish the Water Energy Consortium (WEC) under the Central Asian Cooperation Organization (CACO) umbrella to provide the institutional framework and eventually the legal framework to address these issues. A key first step is that CACO members should reconcile the differing views each of them currently has on the role of WEC.

Export Markets Outside the Region

13. Afghanistan, Pakistan, Iran, China and Russia are all potential markets for electricity produced in Central Asia. There are, however, certain constraints that will have to be overcome to access any of these markets.

14. ***Afghanistan*** currently experiences severe power shortages. It has a small supply base and it lacks resources to build new capacity. Imports represent a near term option to meet its demand requirements. However, its lack of resources also translates into difficulty in paying for electricity imports. Consequently, while some trading activity between Central Asia and Afghanistan can be expected, it is unlikely to represent a significant market outlet for Central Asian exports.

15. ***Pakistan*** is projected to face power supply shortages. Imports may well represent the least cost option to meet future demand. Of particular note is the fact that Pakistan experiences its peak demand in the summer when Central Asia has substantial surplus generating capacity. However, in order to access the Pakistan market a 500 kV transmission line will have to be constructed. Pakistan has expressed considerable interest in securing access to electricity supplies from Central Asia and this may ultimately help mobilize the funding needed to construct the transmission line across Afghanistan, but construction of such a line is a key hurdle that will have to be overcome.

16. ***Iran*** experiences supply shortages during the summer. It purchases some electricity from Turkmenistan but could also have an interest in supplies from other Central Asian countries. In order to access the Iranian market, however, such supplies will have to transit either Afghanistan or Turkmenistan and Uzbekistan.

17. ***China*** is experiencing a severe power shortage currently and Central Asian electricity has the potential to be an inexpensive import option to meet demand in the Urumqui area of the Xingjian province. The major growth in demand, however, will be in the population centers on the east coast of China where transmission distances for supplies from Central Asia become an issue.

18. ***Russia*** has an interest in balancing its system at the border with Central Asia (i.e. the border with Kazakhstan). It also views Central Asia as a potential source of inexpensive electricity supply that could support its ambitions to expand electricity exports to Europe. A 500 kV north-south transmission line is under construction in Kazakhstan. In addition to facilitating intra-regional trade this line could be used to transmit electricity from the Kyrgyz Republic, Tajikistan and Kazakhstan to Russia. RAO UES of Russia has expressed particular interest in securing access to electricity supplies in the future from Central Asia and has made specific commitments to Tajikistan concerning the Sangtuda I hydropower project.

Potential Access to These Markets

19. A number of new generation projects have been identified in Central Asia and developed to the point where they could be constructed. Indeed, several of these projects have been partially completed. For example: construction of hydropower projects at Kambarata in the Kyrgyz Republic and at Sangtuda I and Rogun in Tajikistan were under construction during the Soviet era. Following the break-up of the Soviet Union, however, construction on these projects ceased.

20. While projects such as the Talimardjan Thermal Power Project I in Uzbekistan and the Bishkek II Thermal Power project in the Kyrgyz Republic may be able to proceed on the basis of demand requirements within Central Asia, the economic viability of the majority of the identified projects is predicated on securing assured access for a substantial portion of their electricity production to markets outside the immediate Central Asia region. Accessing these markets is likely to be very much a demand driven process.

21. Table ES3 summarizes the economic and financial costs of the electricity generated from these projects[5]:

[5] These calculations are made on a base case set of assumptions. Sensitivities are discussed in the main body of the report

Table ES 3: Supply Costs from Generation Options						
No.	**Country**	**Supply Option**	**Capacity in MW**	**Economic cost/kWh in Cents**	**Financial cost/kWh in Cents**	**Rank**
1	Uzbekistan	Talimardjan Thermal Power Project I	800	1.68	1.75	1
2		Talimardjan Thermal Power Project II	2,400	2.76	2.92	5
3	The Kyrgyz Republic	Bishkek II Thermal Power Project	400	2.55	2.67	4
4		Kambarata Hydropower Project I	1,900	7.17	8.54	9
5		Kambarata Hydropower Project II	360	3.72	3.95	7
6	Tajikistan	Sangtuda I Hydropower Project	670	1.97	2.44	2
7		Rogun Hydropower Project Phase I	1,200	2.46	2.91	3
8		Rogun Hydropower Project Phases I and II	3,600	2.83	3.24	6
9	Kazakhstan	New Ekibastuz Thermal Power Project	1,000	4.54	5.05	8

Source: World Bank analysis

22. All of these projects except Kambarata I and the new Ekibastuz project are partially constructed – Talimardjan is the furthest along and Kambarata II the least progressed. These projects have the advantage that only incremental costs needed to effect completion must be recovered and there are no liabilities associated with the projects.

23. After the addition of transmission costs, most of these projects would be competitive in the identified export markets. The clear exception is Kambarata I. A comparison of marginal costs of generation and projected import costs (based on the financial costs of the projects and transmission lines) in the various markets is shown in Table ES4.

Table ES 4: Marginal Costs of Generation in Target Markets versus Import Costs (cents/kWh)				
Target Market	Marginal Generation Cost in Target Market	Supply Options	Transmission Cost	Total Landed Cost of Imports
Afghanistan	3.7	Sangtuda I, Rogun I, Talimardjan I and II	0.51	2.26 – 3.43
Iran	3.6	Sangtuda I, Rogun I, Talimardjan I and II	0.54	2.29 – 3.46
Pakistan	5.6	Sangtuda I, Rogun, Talimardjan I and II, Kambarata II	0.51	2.26 – 3.75
China	3.6	Sangtuda I, Talimardjan I	0.72	2.47 – 3.16
Russia	3.0	Sangtuda I, Talimardjan I	0.55	2.30 – 2.99

Source: World Bank analysis

24. While Central Asian supplies should be cost competitive in these markets, the cost advantage is not overwhelming. Electricity trade is more politically sensitive than general trade since electricity supply is often viewed as a national security issue. Also, trade of significant amounts of electricity requires long-term commitments and a clear perception, in the importing countries, that the supplier can be relied upon to fulfill its commitments. The level of trade that will justify the construction of major facilities to service the export markets and the associated commitment of capital will be predicated on the alleviation of supply security concerns on the part of the importing countries and an associated perception that the political climate and the business environment in the exporting countries are stable.

25. It appears likely, therefore, that trade with the markets outside the immediate Central Asia region will initially be limited to seasonally based activity at the margin. However, as trade in electricity establishes a positive track record, the potential for expanded activity will increase. Consequently, the Central Asian suppliers of electricity should approach the issue of expanded export activities with the recognition that a significant expansion in export levels will take some time to develop, and they should, therefore, focus on the objective of building towards this longer term goal in a phased fashion.

CHAPTER I: INTRODUCTION

1.01 The Central Asian Republics (CARs) consisting of Kazakhstan, the Kyrgyz Republic, Tajikistan, Turkmenistan and Uzbekistan are endowed with significant energy resources. However, as Table 1.1 indicates there is considerable disparity in the specific endowments. While Kazakhstan, Uzbekistan and Turkmenistan enjoy world class endowments of fossil fuel resources, the Kyrgyz Republic and Tajikistan enjoy very limited access to these resources but do have significant endowments of water resources.

Table 1. 1: Primary Energy Resources in Central Asia

Fossil Fuel Reserves	Unit	Kazakhstan	Kyrgyz Republic	Tajikistan	Turkmenistan	Uzbekistan	Total
Crude Oil	MTOE	1,100	5.5	1.7	75	82	1,264.20
Natural Gas	MTOE	1,500	5	5	2,252	1,476	5,238
Coal	MTOE	24,300	580	500	Insignificant	2,851	28,231
Total	MTOE	26,900	591	507	2,327	4,409	34,734
% of Total		77.4	1.7	1.5	6.7	12.7	100
Hydro Potential	GWh/year	27,000	163,000	317,000	2,000	15,000	524,000
	MTOE/year	2.3	14	27.3	0.2	1.3	45.1
% of Total		5.2	31.1	60.5	0.4	2.9	100

1.02 The energy and water infrastructure assets that these countries inherited reflect the regional approach employed by the central planners of the Soviet Union. This infrastructure implicitly contemplated energy and water transfers across administrative boundaries that have since become national borders and the design reflected perceived needs within the region.

1.03 The water management system was designed primarily as an irrigation system, with power generation being incorporated as a by-product. Energy systems were then designed to take account of the location of various energy sources and resulted in the following key elements:

- The Central Asia Transmission System was designed as a regional power grid, utilizing hydropower exports from the Kyrgyz Republic and Tajikistan as well as allowing interchange of power among all the countries. The dispatch center for this system was and is located in Uzbekistan.
- The gas pipeline network was designed to allow delivery of gas to the southern portion of Kazakhstan, to the Kyrgyz Republic and to Tajikistan from Turkmenistan and Uzbekistan.
- Oil refineries were located in the more significant oil producers – Kazakhstan, Uzbekistan and Turkmenistan with refined products being transported into the Kyrgyz Republic and Tajikistan.
- Coal consumption was largely tied to the local availability of coal and to the ability to use the rail network for coal transportation.

1.04 At the time of the break-up of the Soviet Union a number of power generation projects were under construction in the Central Asian republics. These included large hydro-projects such as Rogun and Sangtuda I in Tajikistan and, to a lesser extent, Kambarata in the Kyrgyz

Republic. Investments had also been made in a number of large thermal power projects such as Talimardjan in Uzbekistan, Ekibastuz in Kazakhstan and a second combined heat and power (CHP) plant at Bishkek in the Kyrgyz Republic.

1.05 With the break-up of the Soviet Union, these countries inherited extensive energy networks that had been designed to function on a regional basis, but they also inherited a substantial amount of partially constructed infrastructure that had also been predicated on the continuation of a regional approach to managing energy and water issues. At that point, each of the countries was faced with the need to establish formal relations with the other countries in the region covering energy trade and water resource transfers. In addition, they had to take over responsibility for the operation and maintenance of the infrastructure facilities within their own countries and are faced with having to define the optimum means of financing and constructing the new infrastructure facilities that will be required to sustain the energy and water sectors in the region over the longer term (i.e. beyond 2020).

1.06 A key consequence of the new environment that emerged after the break up of the Soviet Union has been a move towards increasing energy self-sufficiency at the expense of regional synergies.

1.07 All the countries, with the possible exception Kazakhstan (which has been able to attract significant private sector participation in the sector), have been keen that the World Bank and other multilateral/bilateral financiers help them finance expansion of generation facilities, including some of the projects that had been under construction at the time of the break-up of the Soviet Union. However, these requests have made within the context of the policies of national self-sufficiency being pursued by the CARs. The World Bank's view is that all these large projects would be feasible only in the context of: (a) significantly enhanced electricity trade, both within the CARs and with external electricity markets; (b) a significantly increased level of regional cooperation among the riparian states relating to the rivers on which such projects would be located; (c) adoption of innovative measures to structure the entities to construct, own and operate these assets; and (d) serious efforts to attract foreign private investments, especially in the context of most of these countries being already highly indebted.

1.08 Of late, there has been an increasing recognition of the need for regional cooperation among the countries in various sectors such as energy, water, transport and food security. The formation of the Central Asian Cooperation Organization (CACO) in 2002, overseen by a Council of the Heads of States of four of these countries[6], for this purpose is a clear indication of the importance they attach to the promotion of such cooperation. In his letter dated September 8, 2003, the President of Kazakhstan, writing on behalf of all four Heads of State, confirmed their intention to enhance regional cooperation in the above areas and invited the World Bank to take the lead in assisting to set up the Water and Energy Consortium, the twin objectives of which are enabling cooperative water usage and enhancement of internal trade and export of electricity.

[6] Turkmenistan is not a member of CACO. Since May 2003, it is not a part of the Central Asian Power System and operates in an island mode. This Study therefore does not cover Turkmenistan and deals largely only with the remaining four countries.

1.09 The World Bank, working closely with other multilateral and bilateral financiers (a.k.a. Development Partners) has followed a two-track approach. The first track had been directed at the near term objective of solving the problems caused by the water-energy nexus, by securing multi-lateral agreement to a series of measures to improve the 1998 Framework Agreement. Key recommendations were contained in the World Bank's report on the Water and Energy Nexus in Central Asia that was distributed to governments of the four countries prior to the consultations that took place earlier this year. Details of the findings arising from this work are presented in Chapter III.

1.10 The second track addressed longer term measures including preparation of this Regional Electricity Export Potential Study, continuation of efforts, in coordination with Development Partners, to promote energy and water sector reforms, estimation of investment requirements for major projects, and exploration of ways to include Russia in the regional cooperation process.

1.11 The CARs have asked the World Bank to help identify the potential for electricity exports outside the region and also the impediments that need to be addressed to realize such potential. However, these countries also need to assess how best to meet their own future requirements for electricity. This study, therefore, addresses (a) options for meeting future electricity demand within the region; (b) the potential scope and location of export markets outside the region and (c) the prospects for accessing these markets.

1.12 The remainder of this Study: reviews the current state of the electricity systems in each of the CARs (Chapter III); assesses the long-term (20-year) domestic demand for electricity and available supply options within each republic and therefore of the region (Chapter IV); undertakes an in depth assessment of the large projects that form a significant part of supply options and identifies broadly the costs of transmission required to reach the target markets (Chapter V); reviews the possible export markets for Central Asian electricity (Chapter VI); identifies an institutional framework for the countries to have a more coordinated and integrated development of their energy resources and water use (Chapter VII); and clarifies the benefits and more importantly the risks, that the countries need to overcome, as well as the way forward to realize the potential (Chapter VIII).

CHAPTER II: THE WATER ENERGY NEXUS IN THE SYR DARYA BASIN

2.01 The Bank's report, Water Energy Nexus in Central Asia, focusing on the Syr Darya Basin, complements the significant amount of work done earlier on water resources earlier under the Aral Sea – Water and Environmental Management Project. Its key findings and recommendations are summarized in Box 2.1.

Box 2. 1: A Brief Summary of the Findings of the CAWENS Report

Toktogul reservoir in the Kyrgyz Republic was designed during the Soviet rule as a multi-year storage facility to enable the storage of water inflows in wet years, for irrigation use in downstream countries during the normal and dry years. The irrigation oriented operating regime called for the release of 75% of the annual releases of water from the reservoir in summer months and for restricting the releases during the winter season to 25% of the annual release. Power generation followed the irrigation regime and the excess power produced in summer was fed into the Central Asian Power System for use by Kazakhstan and Uzbekistan and winter deficits in energy in the Kyrgyz Republic was met by allocation of fossil fuels needed for heat and electricity from Uzbekistan and Kazakhstan.

Once the Soviet Union was dissolved and these countries became independent, these arrangements came under great strain. Toktogul reservoir came to be increasingly used to meet the power needs of the Kyrgyz Republic, reducing summer releases and increasing winter releases of water causing irrigation problems in summer and flooding problems in winter in the downstream countries. To mitigate this problem, a 1998 Framework Agreement among the upstream and downstream riparian countries sought to compensate the former by the latter for the annual and multi-year water storage services through the purchase of surplus summer electricity from the Kyrgyz Republic and supply of fossil fuels needed for Kyrgyz winter needs. In actual practice the annual agreements concluded under this arrangement proved unsatisfactory and difficult to enforce.

The Bank's CAWENS report carried out an economic analysis which demonstrated that net Syr Darya basin benefits are substantially higher under the irrigation regime of reservoir operation (i.e., a minimum of 6 BCM of water releases in summer and a maximum of 3 BCM of water releases in winter) than under the power regime (i.e., reduced summer releases and increased winter releases). While it duly recognized the major contribution made by the Framework Agreement in an attempt to restore the sensible reservoir operating regime, it pointed out the key areas in which the Framework Agreement should be improved to ensure better implementation. These relate to: (a) the need to pay explicitly for the water storage services in cash; (b) the need to use a multi-year rather than annual perspective to take into account unusually wet and dry years as well as normal years; (c) the need to divide the compensation package for water storage services into a fixed and a variable component; (d) the need to link the fixed portion of the compensation to the value of the Kyrgyz fossil fuel needs for the winter months; and (e) the need to have a monitoring and guarantee mechanism to ensure compliance with agreed obligations.

Further, the Study highlighted the areas for institutional improvement to ensure more effective water and energy coordination, regulation, monitoring and enforcement.

2.02 This report was discussed in a conference of Development Partners held in February 2004. Following this conference, the Bank carried out consultations with the CARs in March 2004 to identify key areas where additional work is needed to build consensus among the parties involved.

2.03 The country consultations revealed that each riparian country has a somewhat differing position regarding operation of the Naryn Cascade and Syr Darya:

- The Kyrgyz Republic is of the view that water should be sold to the downstream countries and has adopted national legislation for the sale of water to other countries.

- Tajikistan, while acknowledging that its role is small, views its role as crucial nevertheless, for a balanced operation of the entire basin facilities.
- Uzbekistan believes that solutions should be based on an "international legal framework of trans-boundary waters" such as the Helsinki Agreement, essentially implying that monetizing the compensation mechanisms in the 1998 Framework Agreement, them are not acceptable.
- Uzbekistan also favors the construction of re-regulating structures downstream on its own territories to ensure irrigation supplies, to lessen the dependence on other countries, especially the Kyrgyz Republic with respect to Toktogul operations.
- While Kazakhstan does not currently have any firm plans to build re-regulating structures on its territory, it has not ruled this option out.
- The downstream riparian states (Uzbekistan and Kazakhstan) highlighted the structural deficits in winter energy supply that would be likely to compel the Kyrgyz Republic to be non-compliant with the 1998 Agreement even if the downstream countries were fully compliant.

2.04 In addition, more recently, downstream countries have initiated the following efforts, which have changed the parameters for Toktogul reservoir operations:

- Kazakhstan has promoted works towards increasing the conveyance capacity of the Syr Darya River to pass flows to Northern Aral Sea in winter.
- Uzbekistan, meanwhile, has intensified efforts to increase its downstream water-regulating reservoir capacity in the Fergana valley.[7] The completion of these reservoirs could provide additional storage of about 2.5 BCM downstream, which could absorb the equivalent additional discharge from Toktogul in winter and subsequently release the same quantity of water again in summer for downstream irrigation.
- Furthermore, the dam safety of Kairakum and Shardara dams is being enhanced allowing better re-regulation of water in these facilities, while current usage of available winter water downstream for leaching and growing winter wheat also helps absorb greater winter releases from upstream.
- Large reserves of underground water in Fergana valley also offer possibilities to increase irrigation supply in summer through groundwater development on a sustainable basis.

2.05 At the same time, the latest hydrologic analysis prepared by USAID suggests that the average annual inflows to the Toktogul reservoir are about 12 billion cubic meters (BCM). The implication of the efforts by the downstream countries is that, with the benefit of improved downstream storage and carrying capacity, Toktogul can be operated under a ***modified irrigation regime*** making higher releases during winter for energy generation for the Kyrgyz Republic, without endangering the irrigation water supplies during summer. Taking account of seasonal variation and optimum reservoir levels for power generation, winter releases of around 4.5 BCM are considered sustainable.

[7] Uzbekistan is proceeding with the design of new water storage capacity {Karamansay reservoir of 0.690 billion cubic meters (BCM)}, and is also continuing the construction of Razaksay (0.650-0.750 BCM) and Kangkulsay (0.3 BCM) reservoirs in addition to the existing storage reservoir of 0.8 BCM in the Arnasai depression.

2.06 ***Meeting the Kyrgyz Republic's energy deficits*** in the winter is a key to overcome the current problems induced by the water-energy nexus. The additional 1.5 BCM released would cover around half of the current energy deficit in the winter, while energy efficiency gains in transmission and distribution could feasibly absorb another 20% of the winter deficit. To meet the remaining winter energy shortage, one of the most economic and a relatively quick option would be to invest in an additional 400 MW of thermal generation capacity in Bishkek by finishing the partly constructed Bishkek II power plant (discussed in Chapters IV and V). This would enable the Kyrgyz power system to produce both summer and winter surplus by 2010; and, together with loss reduction efforts and modified irrigation operation of Toktogul, would be able to meet the Kyrgyz Republic's electricity year round until 2020.

2.07 The revised cooperation basis on the Syr Darya basin does imply ***enhanced electricity trade in the short term***. Electricity trade would occur on a commercial basis (i.e., not linked to water releases) and at prices determined by market principles. In addition to possibilities of intra-CAR trade, Russia has indeed become a serious importer of Central Asian electricity, especially the cheaper hydropower from the Kyrgyz Republic and Tajikistan (and it has been exchanging power with northern Kazakhstan for a few years now). To enable this trade with Russia in particular, there is a need to complete the North South transmission line in Kazakhstan, and equally important, access to transmission grids in Uzbekistan and Kazakhstan by the Kyrgyz Republic and Tajikistan are necessary.

A Revised Approach by the Bank and its Development Partners

2.08 Considering the above changes and developments, the approach for the Bank and its Development Partners should remain the same in regard to the long-term track, i.e. mobilizing donor support and resources to help Central Asian countries develop their energy resources in a sustainable manner. However, the strategy with regard to the short-term track should change. Instead of the previously planned efforts to encourage multi-country consensus and contractual agreements in all areas, the focus should be on working to address the institutional, managerial and financial constraints related to power and water ***at the national level*** and promote ***intra-state*** cooperation on water sharing and energy exchange between the Syr Darya riparian states. Such an approach will have three components:

a) ***Work with individual countries on solving power and water management issues.*** This is already a component of the World Bank's Country Assistance Strategies. The particular aspects related to energy-water cooperation are: (i) reduction of electricity losses in all four countries by reinforcement and rehabilitation of transmission and particularly distribution networks; and (ii) increasing ground water development in the Ferghana Valley in Uzbekistan and in Tajikistan, along with improving the safety of the Kairakum reservoir and improving its re-regulation capacity. Also, continued support in improving the conveyance capacity of the Syr Darya River, improvements to the Shardara dam, delta lakes, and Northern Aral Sea, and irrigation and drainage system improvements in each country will improve the water use efficiency.

b) ***Work with Kazakhstan, the Kyrgyz Republic and Tajikistan to improve the energy cooperation among the three countries.*** In addition to providing analytical support, financing options for eliminating the winter energy deficit in the Kyrgyz Republic and strengthening the electricity transmission network in Kazakhstan should be pursued. In particular, consideration should be given to: (i) the completion of the partly constructed Bishkek II power plant, which could potentially export surplus electricity to Russia during Kyrgyz off-peak seasons; and (ii) the construction of the second phase of the 500 kV North-South transmission line in Kazakhstan that is necessary from the point of view of load flow, system stability and ease of transmission for electricity exports to Russia.

c) ***Work with all countries to analyze the long-term energy potentials, provide international experience in water-energy cooperation, and to improve the operational plans at the Toktogul reservoir.*** The World Bank has already proposed an institutional set up for the Water-Energy Consortium (WEC) to the working group dealing with this matter within the Central Asia Cooperation Organization (CACO). Once approved by the CACO Heads of Sate, further support should be mobilized in setting up the WEC, including technical assistance and funding for consensus building. The technical assistance could include provision of further advice on the institutional and legal framework of the Consortium, training and provision of venues for continuing the Consortium dialogue, redesign of the operating rules of the Toktogul reservoir as well as further extension of the analysis of regional power demand, options for expanding the regional power grid, and consequently enhancing the regional exports potential through specific investment projects.

2.09 The Bank and the development partners should give full consideration to the views of all the riparian states and should also incorporate Russia in the dialogue to ensure synergy between the above activity and the ongoing relevant initiatives supported by Russia.

B. The Regional Electricity Export Potential Study

2.10 This Regional Electricity Export Potential Study (REEPS) is a part of the Bank's short- and long-term assistance approaches discussed above. As such, this study is a second (after the Water Energy Nexus Study) in a series of Regional Economic and Sector Work (RESW) initiatives being undertaken by the Bank to assist the CARs in developing a regional approach to meeting their development objectives.

CHAPTER III: CURRENT STATUS OF THE POWER SECTOR IN THE CENTRAL ASIAN REPUBLICS

A. Power System Characteristics

3.01 The power systems in the Kyrgyz Republic, Tajikistan, Turkmenistan, Uzbekistan and south Kazakhstan were developed and optimized as an integrated grid during the Soviet era as the Central Asian Power System (CAPS) which even now operates as a synchronized grid.[8] Details of the power sector in each of the four countries[9] in CAPS are provided in Appendix 3.1.

3.02 ***Capacities and Output***. The capacities and output of the electricity sectors of the Central Asian Republics are summarized in Table 3.1. Two issues merit specific comment. First, the region was a net exporter of about 150 GWh. Second, while gross supply to the domestic market totaled 134,445 GWh, total sales in CAPS to domestic consumers only amounted to 97,984 GWh implying an overall average total system loss level of 27%.

Table 3. 2: Installed Capacities and Supply/Demand Balances of CARs in 2002

Item	Kyrgyz Rep.	Tajikistan	Uzbekistan	Kazakhstan	Total
Installed Capacity Hydro (MW)	2,950	4,059	1,710	2,000	10,719
Installed Capacity Thermal (MW)	763	346	9,870	16,240	27,219
Installed Capacity Total (MW)	3,713	4,405	11,580	18,240	37,938
Available Capacity (MW)	About 3,100	3,428	7,800	13,840	25,068
Peak Demand (MW)	2,687	2,901	7,925	9,432	
Generation Hydro (GWh)	10,778	15,086	7,278	8,861	42,003
Generation Thermal (GWh)	1,115	138	42,021	49,317	92,591
Generation Total (GWh)	11,893	15,224	49,299	58,178	134,594
Exports (GWh)	1,216	266	634	595	2,711
Imports (GWh)	430	1,058	609	464	2,561
Gross supply to domestic Market (GWh)	11,107	16,016	49,274	58,048	134,445
Domestic Billed Consumption Annual (GWh)	6,836	12,988	38,112	40,053	97,989

3.03 The arithmetical sum of their peak demand amounted to 22,945 MW in 2002. Even though the total installed capacity is 40% higher than the system peak, the supply in all countries and especially in the Kyrgyz Republic and Tajikistan remains unreliable on account of the low availability of thermal plants, seasonal variations in water flows in the rivers, restrictions on reservoir operations arising from irrigation demand as well as seasonal variations in electricity demand. Supply shortages are acute in winter (October to March) especially in Tajikistan.

3.04 ***Seasonality of the Electricity Demand***. As shown in Table 3.2, CAPS as a whole is a winter peaking system, where 56% of the total consumption occurs in the winter. Kazakhstan

[8] Turkmenistan's power system was also a part of CAPS from the days of the Soviet era. Since May 2003, however, Turkmenistan is operating in an island mode in relation to CAPS, and is operating in parallel with the Iranian power system and exports electricity to Iran. The reason for Turkmenistan's action is not clear since export to Iran can take place even without such isolation from CAPS.

[9] Hereafter, CARs and CAPS do not include Turkmenistan

and the Kyrgyz Republic have their annual peak in winter, which are substantially higher than their summer peaks. The electricity consumed in winter in the Kyrgyz Republic and Kazakhstan amounts to approximately 67% and 60% of their annual electricity consumption. In the Kyrgyz Republic this is caused by the high share of residential consumers in total electricity consumption and the use of electricity for space heating by households, most of which do not have access to any gas network or any reliable gas supply. South Kazakhstan's winter shortages are caused by limitations of power flow from North Kazakhstan and non availability of export surplus from Tajikistan and the Kyrgyz Republic in winter.

Table 3. 3: Seasonality of the Electricity Consumption of the CARs in 2002

Item	The Kyrgyz Republic	Tajikistan	Uzbekistan	Kazakhstan	Total
Share of Consumption in Summer (%)	33	57	47	40	44
Share of Consumption in Winter (%)	67	43	53	60	56

3.05 The annual load curves of Uzbekistan and Tajikistan are relatively flat, since irrigation pumping loads of summer in these two countries balance the heat loads of winter. In Uzbekistan, availability of gas supply to most areas ensures that winter demand for electricity does not rise unduly. Additionally, in Tajikistan, the aluminum production accounts for the summer consumption being larger than winter consumption.

3.06 ***Power Market Trends and Structure of Demand.*** Due to the collapse of the Soviet Union and the resulting economic turmoil, electricity demand and generation in the CAPS fell dramatically during 1990-1998 and has still not been able to climb back to the level prevailing in 1990. Even more importantly, industrial demand dropped and the share of the residential consumers in total consumption rose dramatically, especially in Tajikistan and the Kyrgyz Republic. This resulted in inadequate loading of some High Voltage (HV) lines and overloading of the Low Voltage (LV) lines and the distribution system, contributing to high levels of technical losses and unreliability of supply. In the Kyrgyz Republic the residential consumption accounted for 58% of total in 2003. In Tajikistan, a state owned Aluminum smelter TADAZ consumes about a third of the total electricity and out of the remaining, nearly half goes to the residential consumers. The share of Tajikistan's residential consumption in the total has risen from 8% in 1990 to 34% by 2001.

3.07 ***System Losses, Billing and Collection.*** These consist of technical losses (undelivered electricity) and commercial losses (delivered but unbilled consumption and uncollected bills). Technical losses have increased well beyond normative values, because of the changes in structure of demand, inadequate maintenance and lack of needed reinforcements of the transmission and distribution system. Unbilled losses arise from theft of electricity, defective metering, meter reading and billing and un-metered supplies billed on the basis of normative consumption. The separation of these components is difficult. It is broadly estimated that the technical loss level is about 18% in Kazakhstan and is 22 to 23% in the other three countries. The unbilled consumption is estimated to range from 5% to 18% in these countries. Nonpayment problem are pervasive and on average only about 70% to 85% of the bills are collected. However, these collection figures include payment through non-cash mechanisms such as barter and offsets, which are still widely prevalent, and cash collection is generally believed to be in the range of 40% to 55% of the billings. Thus, out of the total electricity available, only about 50% is converted into revenues and only about 35% to 40% is converted into cash revenues . Within this overall framework, operational inefficiency varies a great deal among the countries and even among the many distribution companies in Kazakhstan. Data on System Losses, Billing and Collections are summarized in Table 3.3.

Table 3. 4: Losses, Billing and Collections in the CARs in 2002

Item	The Kyrgyz Republic	Tajikistan	Uzbekistan	Kazakhstan
System Losses (GWh)	4,271	3,028	11,162	17,995
System Losses (as a % of net supply)	38	19*	23	31
Total number of consumers (million)	1.1	About 1.0	4.1	About 4.3
Billing (as a % of sales)	80	70	85	N/A
Collection (as a % of billings)	80	70	75	85
Non Cash payment	55%	60%	60%	45%

* Including TADAZ

3.08 ***Regional System Operation.*** The backbone of the CAPS is the 500kV grid which totals 1400 kilometers in length, and almost all major power stations in the CARs are connected to the grid at this voltage. The grid includes a closed central loop connecting the major facilities, with nodal substations located in eastern Uzbekistan, Kazakhstan and the Kyrgyz Republic. Turkmenistan is connected to the CAPS by a 500 kV tie-line (Mari TPP-Karakul), as is southern Tajikistan (Regar-Guzar). In addition, all power systems are interconnected to various degrees through a 220 kV network. Tajikistan could supply electricity to its northern part from the southern part only through power exchanges with Uzbekistan on account of the highly inter twined geographic location of Tajikistan and Uzbekistan and on account of a lack of a north-south transmission link within Tajikistan. Similarly inadequate transmission capacity and stability problems in the North-South 500 kV transmission line restrict the flow of power from the north Kazakhstan grid to the South Kazakhstan grid, which is a part of CAPS.

3.09 The Unified Dispatch Center, Energia, in Tashkent is responsible for maintaining the balanced and synchronized operation of the power transmission and distribution system. Energia also takes into account the irrigation and hydro power related obligations of the member countries (incorporated in the annual Inter-Governmental Irrigation Agreements or IGIAs), balances the real time demand and supply of the integrated grid and ensures system security by arranging for ancillary services such as system reserves, frequency and voltage regulation and reactive power compensation. Energia's Dispatch Service performs the task of translating the quarterly power exchange plans prepared by Central Asian Power Council (CAPC) into daily schedules for generation unit commitment. Energia's Energy Regime Service attempts to balance irrigation and hydropower requirements, which is a controversial issue in the region. Another of Energia's core functions is ensuring overall system security.

B. Policy Reforms in the Power Sectors of CARs

3.10 The CARs have in general adopted policy reforms that are moving the electricity sectors towards a market economy. However, the progress has been uneven among the countries. The current status of policy reforms in each of the CARs is discussed below. Further details of the status of the reform effort in the four countries along with charts of the sector structure are provided in Appendix 3.1.

3.11 ***Legal/Regulatory Framework and Industry Structure***. In all countries a new set of Energy Laws (actually a set of Presidential Decrees in Uzbekistan) have been enacted enabling sector restructuring, corporatization, separate regulation, competitive trading and private sector participation. The policy function has been assigned to the Government Ministries and electricity entities have been corporatized. However, progress beyond legislation and corporatization is very uneven among the four countries:

- Kazakhstan is the most advanced in this regard. More than 85% of the large generation assets (called national level generation) have been separated as independent power producers. The independent transmission company KEGOC is state owned and provides regulated third party access on the basis of regulated transmission tariffs. Distribution is handled by 21 Regional Electricity Companies (RECs), which have smaller embedded generation assets (called regional level generation), transmission at or below 110kV and distribution networks. These RECs are also being unbundled as appropriate and thus nine of the distribution networks have been separated. Price regulation is done by the Anti-Monopoly State Committee. Trading and dispatch is on the basis of bilateral contracts. RECs, distribution companies and large industrial consumers can enter into contracts with generators. Recent innovations include adoption of a Grid Code and introduction of a day-ahead market and spot market.
- There has been progress in the Kyrgyz Republic but less than in Kazakhstan. The sector has been unbundled into one generation company, one transmission company and four distribution companies. There is an independent regulator. The transmission company acts as a common carrier with third party access based on regulated transmission tariffs. Distribution companies directly contract with the generation company. The latter handles exports.
- Progress in Uzbekistan is limited. The state owned joint stock company Uzbek Energo has fully owned subsidiaries for generation units, transmission and 15 distribution areas. The transmission subsidiary acts as a single buyer. Large consumers at 110 kV and above can buy directly from the generators on the basis of regulated tariffs. There is a regulatory body, the independence of which is quite limited.
- The progress is least in Tajikistan where only the modest power sector assets in the Gorno Badakshan region have been given on a 25 year concession to the privately owned Pamir Power Company, which will function as a vertically integrated utility. The power sector assets in the rest of the country remain with Barki Tajik, a state owned joint stock company functioning as a vertically integrated utility, with wholly owned subsidiaries for generation units, transmission and distribution, which for all practical purposes function as divisions of Barki Tajik. There is no independent regulation. The distinction between the government and Barki Tajik is somewhat fragile. A separate Joint stock company has been formed for the construction of the Sangtuda I Hydropower project with the objective of attracting equity from outside the government.

3.12 ***Electricity Tariffs.*** Posted electricity tariffs range from a low of 0.5 cents/kWh in Tajikistan to a high of 2.64 cents/kWh in Kazakhstan, but are below the cost recovery level in all countries, as shown in Table 3.4. There are considerable subsidies in favor of residential consumption in all countries, especially in the Kyrgyz Republic and Tajikistan. Uzbekistan is the most serious in terms of pricing reforms, as it adopted a multi-year tariff adjustment policy that has been in effect since August 2001 (prices are increased by roughly 10% once every 2 months) and aims to reach full cost recovery levels by end 2005. Kazakh tariffs vary widely among the distribution companies and may have reached cost recovery levels in the case of a number of distribution companies.

Table 3. 5: Electricity Tariffs in the CARs in 2003

Item	The Kyrgyz Republic	Tajikistan	Uzbekistan	Kazakhstan
Average tariff (Cents/kWh)	1.40	0.50	2.15*	2.64
Cost recovery level of Tariff (Cents/kWh)**	2.30	2.10	3.50	2.80
Current Tariff as % of Cost Recovery Tariff	61%	24%	61%	94%

*Aug. 2004; ** See Chapter IV and Appendix 5.1 for details

3.13 ***Private Sector Participation.*** Kazakhstan has the most private sector participation. 85% of large generation plants (called national generators) are in private hands, as well as 9 distribution networks are privately operated. The policy objective is to privatize all distribution operations. Tajikistan has given out the investment, operations and management responsibility for the electricity operations in Gorno Badakshan Autonomous Oblast to a private operator under a 25-year concession. In the Kyrgyz Republic, all electricity distribution companies are to be privatized and one of the four distribution companies is planned to be awarded under a concession arrangement in the near future. Uzbekistan has put up four power plants (50% of installed capacity) and 4 distribution companies (30% of consumers) for privatization, and plans to offer 49% of the equity to private investors in generation and distribution companies

3.14 ***Electricity Trade.*** There has been a considerable reduction in the amount of electricity exchanged between the CARs since 1990, as shown in Table 3.5. The total export/import flow in 2000 was only 30% of the 1990 level, even though the consumption levels in each country has recovered to about 80% of the 1990 level. Until 1992 the electricity flows followed Soviet era commodity exchanges based on planned allocation of electricity, irrigation water, and fossil fuels to the regions, but from 1993 onwards the newly independent countries introduced a system of barter payments for the exchange of fossil fuels and electricity based on cash prices. As traded fossil fuel prices went up sharply and electricity prices remained low, the exchange became difficult and electricity trade suffered large declines. Pursuit of national energy self-sufficiency policies by the CARs is also a key reason for the decline in trade. Significant trade of electricity occurs only in the Syr Darya basin, with the Kyrgyz Republic being a net exporter to Uzbekistan and to southern Kazakhstan[10]. The Kyrgyz Republic and Tajikistan, due to their large hydro systems, provide frequency regulation to the wholes CAPS, and they earn fees for providing such services. In 2000, the total frequency regulation services amounted to about 5,000 MW over the 12 months period, which earned them about US$7 million.

---

[10] However, given that there are many links at the medium and low voltage levels (at 35kV especially) across borders, there are transfers of energy between some countries (e.g., the Kyrgyz Republic and Almaty area) that are unrecorded.

Table 3. 6: Shifts in Electricity Trade in Central Asian Power System 1990-2000							
Electricity Trade in 1990 (GWh)							
	Imports						
Exports	Kazakhstan	The Kyrgyz Republic	Tajikistan	Turkmenistan	Uzbekistan	Outside CAPS*	Total Exports
Kazakhstan	--	277	0	0	310	0	587
The Kyrgyz Republic	697	--	0	0	2383	0	3080
Tajikistan	0	324	--	0	2344	0	2668
Turkmenistan	0	0	0	--	6066	0	6066
Uzbekistan	8139	0	3927	946	--	0	13012
Outside CAPS*	0	0	0	0	0	--	0
Total Imports	8836	601	3927	946	11103.2	0	
Electricity Trade in 2000 (GWh)							
	Imports						
Exports	Kazakhstan	The Kyrgyz Republic	Tajikistan	Turkmenistan	Uzbekistan	Outside CAPS*	Total Exports
Kazakhstan	--	0	0	0	0	0	0
The Kyrgyz Republic	1253	--	154	0	1926	0	3333
Tajikistan	0	126	--	0	244	0	370
Turkmenistan	35	0	819	--	68	0	921
Uzbekistan	0	195	729	32	--	0	956
Outside CAPS*	2224	0	0	0	0	--	2224
Total Imports	3512	320	1702	32	2237	0	

*Mainly northern Kazakhstan.

Over the 1990-2000 period, the changes in the electricity trade were as follows:

- Within CAPS, in Kazakhstan imports dropped by 85% from 8.8 TWh in 1990 to1.3 TWh in 2000.
- Although the Kyrgyz Republic, a traditional electricity exporter, registered an increase of exports of 6% in 2000 over 1990, the year 2000 was an exceptional year in terms of water needs of the downstream countries and therefore the electricity exports were high. In reality the exports average around 2 TWh per year, which implies a drop of about 35% in its exports. The Kyrgyz Republic's imports dropped 50% from 0.6 TWh in 1990 to 0.3 TWh in 2000.
- In Tajikistan imports dropped by 56% from 3.9 TWh in 1990 to 1.7 TWh in 2000. In the same period the export went down by 85% from 2.7 TWh to 0.4 TWh.
- In Turkmenistan imports dropped by 97% from 0.9 TWh to 0.03 TWh and export dropped by 85% from 6.1 TWh to 0.9 TWh.
- In Uzbekistan from 1990 to 2000 the import dropped by 80% from 11.1 TWh in 1990 to 2.2 TWh in 2000. The exports dropped by 92% from 13.0 TWh in 1990 to 1.0 TWh in 2000.

3.15 The electricity trade that occurred in 2000 was actually a proxy for water exchanges and, therefore, is an unreliable source of revenue to the electricity exporting countries. Despite the pursuit of national energy self-sufficiency policies, the Kyrgyz Republic and Tajikistan are unable to meet their winter peaks demands for energy.

Policies to be Pursued Going Forward

3.16 The current policy frameworks are generally pointed in the right direction in all countries, except that policy implementation needs to be accelerated to assist sector development. Specifically:

- As regards industry structure, third party access to transmission is an absolute necessity if electricity trade is to be enhanced;
- While independent regulation is a final objective (which may take many years to realize), nearer-term measures that should be pursued are: (a) bringing transparency to regulation; (b) providing multi-year regulatory certainty (e.g., adopting a tariff policy that covers several years); and (c) where private operators already exist, even handed treatment of public and private operators, is necessary.
- As regards pricing, especially for the Kyrgyz Republic and Tajikistan, it is useful to follow Uzbekistan's example and implement a multi-year tariff path to reach cost recovery levels as soon as possible, after taking into account affordability consideration including the provision of a social safety net. In addition to providing the urgently needed resources for investments, proper pricing will also have a beneficial effect on demand, and will give the right signals for intra-CAR trade.
- Private Sector Participation will be important over time, in view of the huge investment need and the weak management capacity.
- There is a need to enhance electricity trade as an integral part of overall energy trade, since such trade would meet demand at the lowest possible cost, given the resource complementarities. However, it should be ensured that energy/electricity trade occurs based on market principles.

3.17 Trade within the region could increase if payments for electricity, water services, and fuels are fully monetized and if the annual IGIAs are based on least cost solutions for the river basins as a whole. Further increases in trade would arise when the transmission systems in all four countries provide non-discriminatory third party access on the basis of transparent transmission tariffs. Metering, payment discipline and settlement mechanisms have to be improved. Further, in order to arrive at rational trade decisions, prices of electricity in all four countries need to reflect the cost of supply.

CHAPTER IV: DEMAND SUPPLY BALANCEAND POTENTIAL FOR ELECTRICITY EXPORTS

4.01 This chapter attempts to answer the following set of questions: what is the current and projected demand for electricity in each of the CARs; what are the supply options to meet such demand, and in turn what is the potential exportable surplus from the CARs.

A. Demand Forecast

(i) Issues in Demand Forecasting in CARs.

4.02 Trending, end-use analysis and macroeconomic modeling are the common approaches to electricity demand forecasting. Given the economic collapse following the dissolution of the Soviet Union and the continued decline in GDP and electricity consumption in the former Soviet Union countries, trending would be inappropriate in the CARs. End-use analysis is really what the countries need to do, but is currently difficult on account of paucity of data and is distorted by the excessively inefficient use of electricity. Demand projections made during the Soviet era and even in years immediately thereafter, were more in the nature of targets to be achieved than in the nature of forecasts. Given the central planning background and practices, price as a determinant of demand was largely ignored and concepts of price elasticity and income elasticity were not much in use. Kazakhstan Electricity Association – a national industry association—has recently commenced the practice of making long-term forecasts. There have also been recent forecasts made by consulting firms financed by International Financial Institutions such as ADB and UNDP, and some bilateral aid agencies in the context of their operations, which use macroeconomic modeling and also incorporate considerations of income elasticity and price elasticity. However they do not appear to have considered seasonal variations in demand adequately. Given the high degree of such seasonal variations, it is necessary to incorporate them in the demand projections to determine export surpluses. Also other key assumptions relating to GDP growth rates, electricity prices and possible efficiency improvements need to be updated. The forecast made in this report on the basis of macroeconomic modeling incorporates these elements. The model is based on a simple iso-elastic demand function of the type often used in such aggregate demand analysis.

(ii) Key Determinants of Demand Growth

4.03 Demand forecasts have been made for the four countries at the aggregate level, by estimating the total sales in GWh for the sector as a whole (without going into the demand at the level of different classes of consumers) and adding to it the estimated transmission and distribution losses to arrive at the demand at the generation level.[11] The details of the model, methodology and assumptions used are presented in Appendix 4.1. Some of the key determinants used are described below.

---

[11] It is worth noting that this demand does not include auxiliary consumption or station use by the generating stations. This consumption could amount to 0.5% to 1% for hydro stations, 4% to 6% for gas fired thermal plants and 6% to 8% for coal fired thermal plants.

- *Income Elasticity or GDP elasticity* of electricity demand: A range of available literature indicates that for most developing countries the GDP elasticity of electricity demand ranges between 1.2 and 1.4 (i.e., for every percentage increase in GDP, the electricity demand increases by 1.2 to 1.4 percent). However, most former Soviet Union states (and more so in the case of CARs) do not fit into this category as their electricity consumption is already very high relative to their GDP level. Therefore, it is expected that the relationship between GDP and electricity demand in CARs would be more akin to those prevailing in developed countries, which have exhibited a GDP elasticity of demand of 0.8. This value had been used in relation to CARs in this study.
- *Price Elasticity*: The estimates for price elasticity of demand for electricity in lower income countries generally are in the range of –0.1 to –0.2, implying that for every percentage increase in electricity price, the demand decreases by 0.1 to 0.2 percent. The elasticity levels for electricity are generally lower than those for other energy forms (e.g., petroleum products), reflecting:
    - consumers' inflexibility to switch from electricity to other forms of energy. This is particularly true of all types of consumers in the short term, and for industries, such as metallurgical and chemical, even in the long term;
    - non-availability of other energy forms (e.g., gas), as is the case in the Kyrgyz Republic and Tajikistan; and
    - the share of industrial consumption in overall consumption – the higher the industrial consumption share as is the case with Kazakhstan and Uzbekistan, the lower the price elasticity of demand.

  It is also important to note that there is an inverse relationship between price elasticity of demand and a country's income (GDP) level. At higher income levels, electricity demand becomes less and less elastic to electricity price changes as GDP increases. This is the case with Kazakhstan, where its higher level of GDP would tend to lower the price elasticity values. Considering all of the above, price elasticity values of –0.1 have been assumed in Kazakhstan and Uzbekistan and –0.3 in the Kyrgyz Republic and Tajikistan (where the needed price increases to reach financial viability are 80% and 300% respectively).
- *Effective Tariffs*: It was also recognized that the effective tariffs paid by the consumers were actually lower than the posted tariffs, due to the poor metering, billing and collection efficiencies. Therefore the applied prices to estimate demand were adjusted by the collection rate to arrive at the effective prices.

(iii) Results of the Base Case

4.04 The results of the base case demand forecast exercise are summarized in Table 4.1 for each country and for Central Asia as a whole. In the short term (up to 2010) the total demand in all four CARs combined is expected to increase at a modest annual rate of 0.31%. Demand is actually projected to decline in Tajikistan, Uzbekistan and the Kyrgyz Republic, whereas in Kazakhstan, there would be a growth of about 2.94% per year. Over the longer term (up to 2025), all countries except Tajikistan would register an increase in demand, resulting in an annual compound growth rate of about 1.9% for the region. Kazakhstan would experience the highest annual rate of growth (3.09%), and demand in Tajikistan would actually decline at 0.17% p.a. compared to the 2003 level.

Table 4. 1: Gross Electricity Demand Projections: Base Case									
Country	Actual	Forecast Demand (GWh)				Annual Growth rates			
	2003	2010	2015	2020	2025	2003-2010	2003-2015	2003-2020	2003-2025
Kazakhstan	58,944	72,056	84,034	98,367	115,146	2.91%	3.00%	3.06%	3.09%
The Kyrgyz Republic	12,145	9,222	10,033	11,296	12,719	-3.86%	-1.58%	-0.43%	0.21%
Tajikistan	16,348	11,267	12,410	13,972	15,731	-5.18%	-2.27%	-0.92%	-0.17%
Uzbekistan	48,691	46,597	51,255	56,589	62,479	-0.63%	0.43%	0.89%	1.14%
All Four Countries	136,128	139,142	157,731	180,225	206,075	0.31%	1.24%	1.66%	1.90%

4.05 Kazakhstan's high growth rate in electricity demand among the four countries is on account of (i) the high sustained GDP growth projected over the period; and (ii) the fact that since its tariffs are already at 94% of cost recovery levels (Chapter III, Table 3.4), the effect of price increases on demand growth would be minimal. The Kyrgyz Republic would actually experience a contraction in demand during 2005-2020 as a result of significant increases in metering, billing and collection leading to a real effective tariff increase of 103% over the period, when collection rates are factored in. There would be modest demand growth thereafter. Tajikistan's demand would also decline through 2025 for a similar reason - on account of its very low tariff base, tariff increases and improvement in collections would lead to real effective tariff increases of five times the level in 2003. Uzbekistan's demand would also decline through 2010 but would experience a modest growth rate thereafter. The key reasons for a relatively flat demand curve in Uzbekistan are: (a) extensive gasification of the country in the 1990s, resulting in over 87% of the population having access to gas supplies; (b) relatively lower GDP growth rates, and (c) an assumed increase in real effective tariff of 37% over that period.

(iv) Seasonal Variations in Demand

4.06 As discussed in Chapter III, seasonal variations in electricity demand are significant in the CARs. The CAR region's annual peak occurs in winter, and consumption during winter (October-March) is substantially higher than in summer (April-September) generally as a result of using electricity for space heating. The variation is highest in the Kyrgyz Republic followed by Kazakhstan, Tajikistan and Uzbekistan in that order. In the Kyrgyz Republic (and to a large extent in Kazakhstan also) gas distribution is limited and electricity is used for space heating. In Tajikistan the increased heat load in winter is somewhat balanced by the irrigation pumping load in summer. In Uzbekistan the seasonal variation is not pronounced on account of extensive gas distribution. For the region as a whole, 58% of the annual consumption takes place in winter (Fig 4.1). This need to be factored in and the supply demand balances need to be worked out on a monthly basis to plan for system expansion and for determining the exportable surplus.

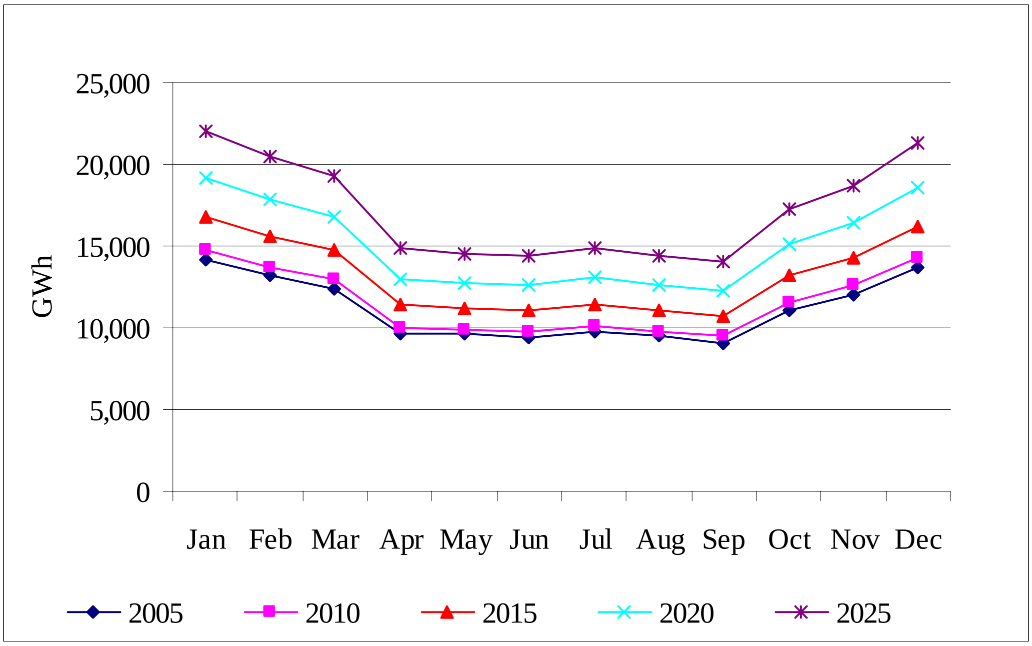


Figure 4. 1: Gross Electricity Demand in CARs, Monthly Totals, 2005 - 2025

(v) Sensitivity Analysis

4.07 In view of the fact that the key determinants of demand, price and income elasticity levels chosen were based on experience elsewhere and not in the CARs, the demand projections were subjected to extensive sensitivity analyses by varying the key determinants of demand – price and income elasticity – in both directions. In addition, the projections were tested for delay or acceleration in reaching cost recovery tariffs. The results are summarized in Table 4.2 and elaborated in Appendix 4.1.

Table 4. 2: Results of Sensitivity Analyses on Demand Forecast

Country	Percentage Change in End-of-Period Demand for every	
	1% Change in Income Elasticity	1% Change in Price Elasticity
Kazakhstan	0.74	0.08
The Kyrgyz Republic	0.53	0.52
Tajikistan	0.64	0.74
Uzbekistan	0.45	0.22
All four Countries	0.63	0.20

4.08 Sensitivity analyses showed that demand growth in the region overall is more sensitive to income elasticity values compared to price elasticity. Over the 2005 – 2025 period, every 1% decrease in income elasticity projected demand would decrease by 0.63% compared to 0.2% change in demand for every 1% change in price elasticity. However, projected demand in individual countries behaves differently. Projected demand in Kazakhstan is more sensitive to changes in income elasticity and least sensitive to changes in price elasticity, confirming the international experience that as incomes grow, electricity demand becomes less and less elastic to price changes. Tajikistan, the poorest of the CARs, is more sensitive to price changes. Given the dominant size of the Kazakhstan and Uzbekistan systems within CARs, the regional demand growth patterns will reflect the growth patterns in these two systems. The changes in the timing of projected tariff increases had only a minor impact on projected demand.

B. Supply Options

4.09 The supply options to meet the projected demand include (a) projects for rehabilitation of the transmission and distribution system to reduce the high level of Transmission and Distribution (T&D) losses; (b) projects for rehabilitating the existing generating units; and (c) construction of new generating plants.

(i) Loss Reduction

4.10 Reduction of technical losses in the T&D system is the most economical method of meeting the incremental demand when the loss levels are high compared to industry standards. Table 4.3 below indicates the existing and targeted loss levels in the four countries and the volume of incremental demand such reduction would help to meet. Much of the losses are occurring in the low voltage distribution systems, since the consumption structure has shifted more towards residential consumption in all countries. This shift is most pronounced in the electricity dependant Kyrgyz Republic and Tajikistan. Though losses in the transmission systems, as reported at about 8%, are higher than the industry standard of 4% to 5%, most of the system is still carrying loads lower than their design capacity (the overall power transmitted in 2003 was still only 90% of the level it carried in 1990); and considerable investments have already been made in the transmission system[12].

Table 4. 3: Current and Targeted Electricity Loss Levels in CARs

Country	Current Losses* (%) (2004)	Target Loss Levels (%)	Time Period of the Projects	Additional Annual Electricity (GWh) in 2010
Kazakhstan	24	15	2004-2010	5,843
The Kyrgyz Republic	34	13	2004-2010	1,392[13]
Tajikistan	28	13	2004-2010	1,988
Uzbekistan	25	15	2004-2010	4,064

*Includes technical losses mainly, but also some commercial (unbilled consumption) losses.

4.11 The focus of future investment thus would be more on distribution rehabilitation, reinforcements and expansion. The projects for the reduction of losses in all four countries implemented during 2005-2010 would make available an annual incremental supply of 13,287 GWh of electricity by 2010. The total value of investments on such transmission and distribution loss reduction projects in all four countries is estimated at $3,009 million in 2004 prices.

[12] Roughly US$80 million of a foreign funding of power sector investments in Kyrgyz Republic has been spent on transmission, and ADB and EBRD are assisting Uzbekistan with its transmission system improvement, ADB is assisting Tajikistan to invest in rehabilitation of its transmission system; and World Bank is assisting Kazakhstan.

[13] An additional 220 GWh would be realized in 2011.

(ii) Rehabilitation of Generation

4.12 Major hydropower stations in the region are generally in reasonably good condition. Rehabilitation of Nurek hydropower station in Tajikistan has already been funded. In the Kyrgyz Republic the main thermal plant (Bishkek CHP-I) has already undergone feasible rehabilitation. The rehabilitation of the CHP units in Tajikistan would add relatively small amounts of electricity. On the other hand there is considerable scope for rehabilitation of thermal power stations in Uzbekistan and Kazakhstan to secure increased power generation from them.

- In *Uzbekistan* UzbekEnergo estimates that out of the total installed thermal generating capacity of 9,870 MW (consisting of 11 thermal plants) only about 8,200 MW is actually available. If units well beyond the age of 35 years and or 200,000 hours of operation are also excluded the available capacity would be even lower at 7,800 MW. UzbekEnergo, with considerable support from the Government, is undertaking rehabilitation of the country's electric generation capacity through several projects, including an US$81 million loan from EBRD for the renovation of the Syrdarya plant and a US$200 million loan from Japan Bank for International Cooperation (JBIC) for the rehabilitation of Tashkent coal fired station. Further rehabilitation of two units at Syrdarya as well as the rehabilitation of the Angren, Navoi Angren units are planned. When all the planned rehabilitation of power plants is implemented over the 2004-2023 period at a cost of US$1.15 billion, the operational life of all major power plants would have been extended avoiding the loss of generation of about 32,000 GWh (during 2005-2025) due to retirements.

- In *Kazakhstan***,** large thermal power plants (called "National level" power plants) provide considerable generation volumes of electric power. These are the Ekibastuz I and II, Aksu and Karaganda coal fired thermal power plants, There is a need for rehabilitation of the thermal power plants since all of them are operating at low plant use factors (29% at Ekibastuz I compared to a design value of 77%; 51% at Ekibastuz II; 52.5% at Aksu; and 54% at Karaganda); and 58% of the total installed thermal capacity or about 10,600 MW, will reach the end of its operational life before 2015. The rehabilitation of Ekibastuz I plant is expected to cost $440 million and result in the annual incremental generation of 11,283 GWh. The Kazakhstan Electricity Association (KEA) estimates that roughly US$1,070 million is needed to rehabilitate the thermal power plant (US$770 million for all other national power plants and $300 million for the regional plants owned by the Regional Electricity Companies) to extend the operational lives of the units and improve the plant factor to 60%. With such rehabilitation, the incremental annual generation from those plants would amount to 17,118 GWh.

(iii) New Generation Projects

4.13 Large new power plant projects are contemplated in all four countries and they are briefly discussed below[14].

---

[14] It is important to note that the information on costs, time to completion of construction etc, are obtained from country authorities, and have not been independently verified. Such verification would come when investment commitments would be contemplated.

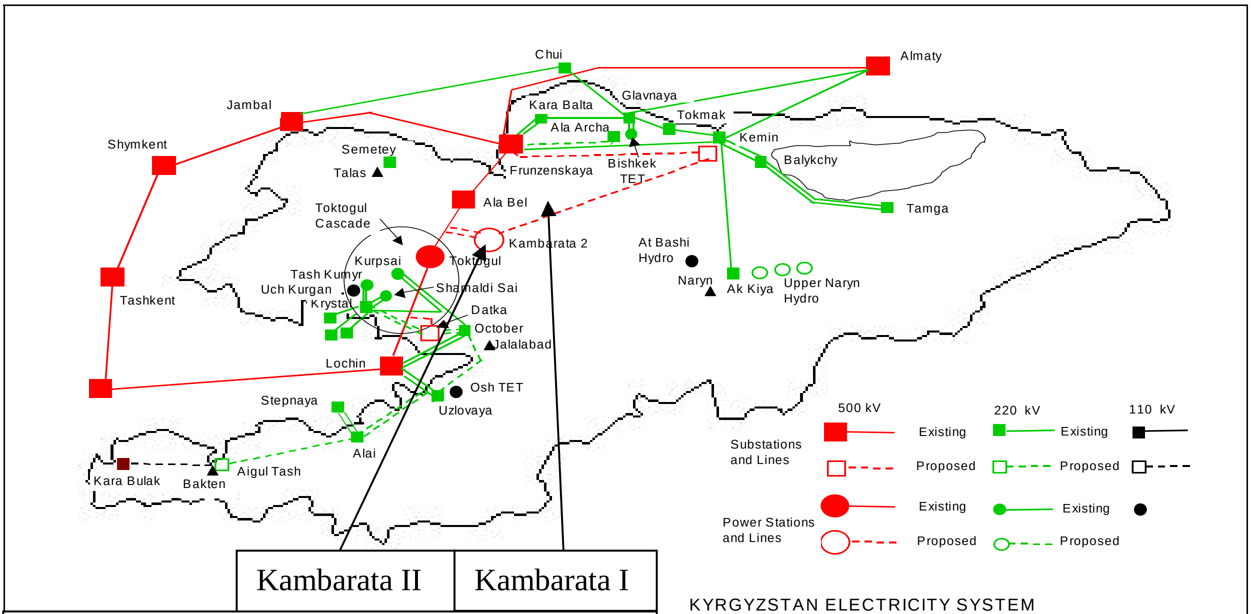
- *New Ekibastuz Thermal Power Station in Kazakhstan*[15]*:* The existing Ekibastuz II power station consists of two coal fired units of 500 MW each located in a site which has all the infrastructure and site facilities to accommodate easily two more units of 500 MW each. The original project planning was done during the Soviet era on this basis. A recent study has estimated the cost of construction of these additional units at $1,085 million.[16] The implied cost per kW of about $1000 is lower than the international reference cost of $1300 per kW reflecting the availability of basic infrastructure.[17] This project is expected to be implemented during 2008-2011 and is expected to result in an incremental annual generation of 7,446 GWh.

- *Bishkek II Thermal Power Plant in the Kyrgyz Republic:* This plant, referred to sometimes as Bishkek CHP II, is a plant that is partly constructed Its construction began in 1985, but has been put on hold since 1992. The original scheme was to develop a combined heat and power plant of 800 MW, including seven heat-only-boilers as Phase 1 of the plant. Two of the seven planned heat-only-boiler units, as well as the building housing the boilers, water treatment facilities, natural gas and fuel oil supply/storage installations, flue disposal structure (chimney) and a railway line within the land allocated to the plant of about 47 hectares have been installed. The plant is designed to use mainly natural gas from the Tashkent-Almaty gas pipeline. In addition, a newly equipped 220-kV substation is located just next to the plant site, which will facilitate the evacuation of power. Constructing a new gas fired 400 MW thermal plant using the combined cycle technology making the best use of the existing site facilities is perhaps the most cost-effective and rational solution to meet the winter power shortages of the Kyrgyz system. Allowing one year for engineering and raising finances, and two years for construction this plant could be commissioned in 2007, enabling an annual incremental generation of 2,453 GWh from 2007 or 2008. Taking into account the site facilities already available the capital cost is not expected to exceed $200 million.[18]

- *Kambarata I and Kambarata II Hydroelectric Projects in the Kyrgyz Republic* are being actively pursued by the government. Kambarata I is a 1,900 MW storage hydroelectric facility, identified and designed during the Soviet era, located in the middle part of the Naryn river upstream of the Toktogul reservoir (see Figure 4.2). As proposed, it would be a 275 meter high dam built by controlled blasting and would include the associated power/spillway tunnels, penstocks and power generation facilities. The reservoir would have a live storage of about 3.4 BCM and would provide seasonal storage. The maximum net head of the dam would be 180 meters and annual energy generation would be about 5,000 GWh with a plant use factor of about 30%. Since it is located upstream of Toktogul reservoir (which has a much larger live storage of 14 BCM), water could be released from Kambarata I to generate almost all of its annual power output in the winter, thus

[15] This is a state owned power plant in which 50% of the equity is believed to have been transferred to RAO UES of Russia in lieu of the electricity arrears, which Kazakhstan had owed to RAO UES for power imports from Russia.
[16] RWE Solutions/Lahmeyer International: Feasibility Study for the Kazakhstan North-South Line 2002
[17] However, it needs to be verified if this costs include environmental impact mitigation equipment.
[18] Compared to the international reference price of $600 to $700 per kW for a green-field Combined Cycle plant, the plant proposed in Bishkek is likely to cost less than $500/kW.

avoiding the release of water from Toktogul in the winter. Enabling additional generation of electricity during winter without releasing water from Toktogul would be the most significant contribution of this project. The estimated capital cost of Kambarata I is about US$1.67 billion, and together with transmission line costs needed to evacuate power (of about $265 million), the total costs would amount to $1.94 billion (or $1,000/kW). It is anticipated that it would take 8 years to prepare the project and 9 years to construct it and that power would be available starting in 2017, though the full output could be realized only in 2020.



Source: Kyrgyz Republic-UK DfID Tariff Policy Project, 2003

Figure 4. 2: Kyrgyz Power System and Location of Kambarata schemes

- *Kambarata II* would be a run-of-the river hydro project downstream of Kambarata I but upstream of Toktogul (see Figure 4.2). The installed capacity would be 360 MW if Kambarata I is developed, or 240 MW if it is a stand-alone scheme. As proposed, it would be a 62 meter high dam built by controlled blasting, and would include the associated power/spillway tunnels, penstocks and power generation facilities. The average energy production would amount to about 1,100 GWh at 240 MW and 1260 GWh at 360 MW. Almost all the generation, when built as a stand alone project, would be in the summer. About 20% of the project had already been completed and the incremental costs for completing this project are estimated at about $280 million for a 240 MW plant, including the necessary transmission lines. On this basis, the cost per kW of Kambarata II would be about US$1,167. It is important to note that in the absence of Kambarata I, the Kambarata II project should be considered with caution as it would merely add to the summer surplus and would not help to remedy the winter shortage of electricity. However construction is proceeding, albeit slowly, and RAO UES of Russia has reportedly agreed to fund the effort to update the feasibility report and if construction is to begin in say 2008/09 it may be possible to commission it by 2012.

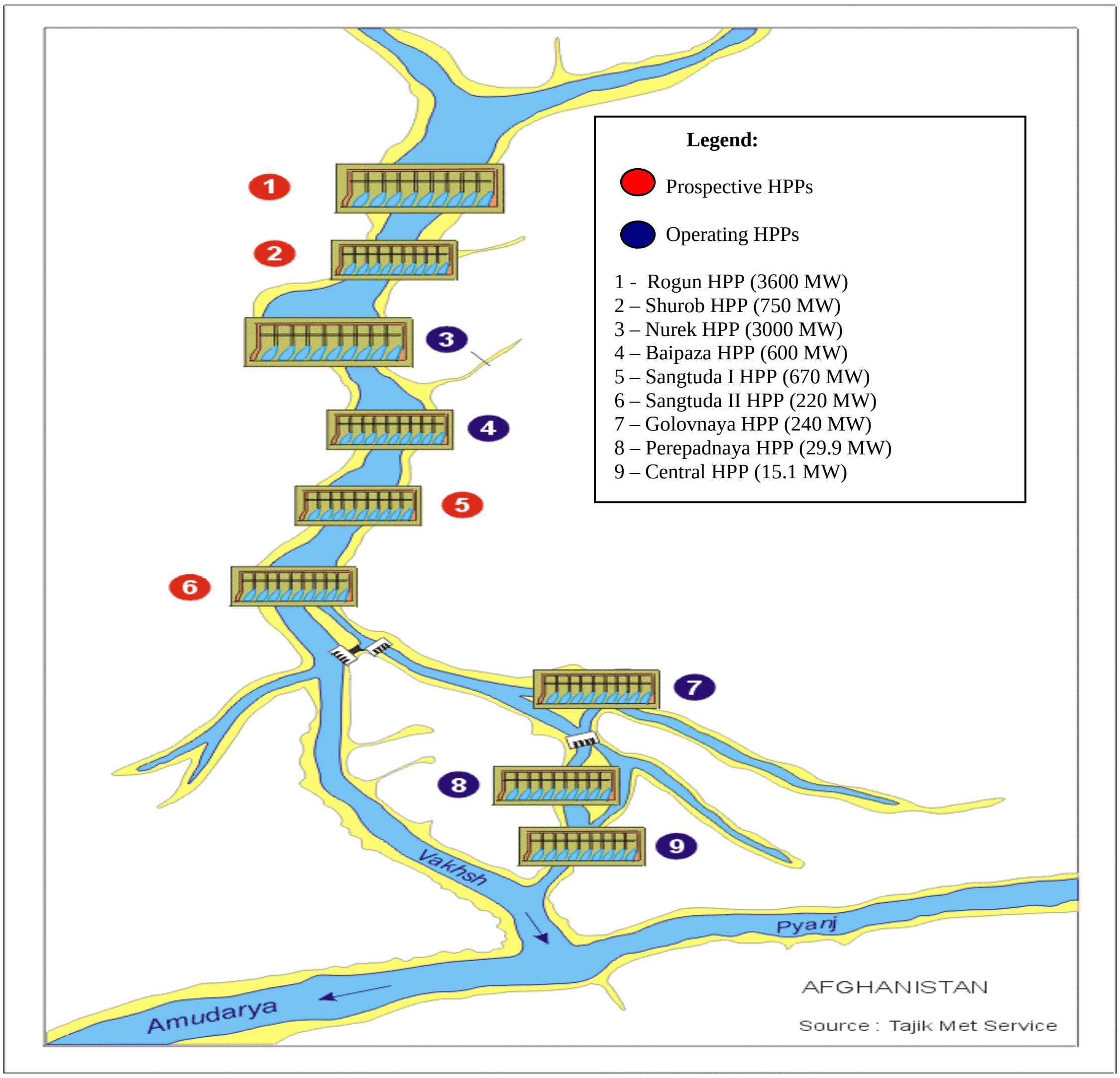


Figure 4. 3: Planned and Existing Hydro Schemes on Vaksh River in Tajikistan

- *Rogun Hydropower Project of Tajikistan* is located upstream of the existing Nurek hydropower cascade on the Vaksh river (see Figure 4.3). The project was planned to be constructed in two phases with an ultimate installed capacity of 3,600 MW. The dam to be built will be one of the highest in the world with a height of 335 meters. The construction of the project commenced during the Soviet era when all the construction machinery was assembled, construction colony was established, and diversion tunnels and most of the excavation needed for the project were completed at a cost of $800 million (as estimated by Tajik authorities). Since 1992 no further progress had been made for want of funds. The incremental costs required to complete this project are about $2.1 billion[19]. In Phase I the remaining works would involve the construction of the dam to two-thirds of its final height, repairing two existing tunnels; building a third new tunnel; creating the regulating reservoir and installing two generation units which would operate

[19] The full costs are estimated by Tajik authorities at about $2.9 billion, of which they claim that $800 million has already been spent.

with a capacity of 800 MW. The electricity output of this Phase I would be about 4,300 GWh, and it would also enable the generation of an additional 400 GWh at Nurek. The funds needed to complete this Phase I are estimated at $785 million.

- Phase II involving completion of the dam to its full height of 335 meters and installation of additional power capacities of 2,800 MW is expected to cost $ 1.67 billion. After completion of Phase II, the whole Rogun scheme would generate roughly 13,000 GWh and the additional generation at Nurek would increase to 1,300 GWh.

- *Sangtuda I Hydropower Project in Tajikistan* is a proposed to be located downstream of the existing Nurek hydropower cascade (see # 4 and 5 on Figure 4.3) on the Vaksh river. The construction of this project also commenced during the Soviet era and was suspended in 1992 for want of funds after completing a sizeable amount of work. The planned installed capacity on this run-of-the-river scheme is 670 MW and expected annual electricity generation would be about 2,700 GWh. About 60% of the generation would be in the summer months (April to September) and the remainder would be during the winter months. The total cost of the project is estimated to be about $482 million, and it is estimated that about $114 million has already been spent. Therefore, a further $368 million would need to be mobilized to complete the project.

- *Talimardjan Thermal Power Project in Uzbekistan* is a gas fired steam turbine plant with 4 units of 800 MW each. It is located in the Mubarek gas field, one of the larger producing gas fields in Uzbekistan. This project was also started during the Soviet times, and the basic infrastructure has been built for the four units. Since independence, Uzbekistan has been attempting to install and commission the first unit, which is expected to come on stream in 2005. It is estimated that about $100 million would be needed to commission this unit, which at a plant factor of 60% would annually produce about 4,537 GWh. This would complete the first phase. The amount of sunk cost already incurred is not readily available. The second phase would involve construction and commissioning of the three remaining units of 800 MW each and would likely to take place during 2009-2013 after firming up possible export sales agreements. The capital cost for this phase is estimated at $ 1.2 billion ($500/kW) taking into account the infrastructure which is already in place. These three units would provide an annual incremental generation of about 13,613 GWh.

(iv) Overall supply increases

4.14 As a result of the implementation of the above mentioned projects the overall gross supply in all four countries would rise from 139 TWh in 2003 to 228 TWh in 2025. About 54% of this incremental supply would come from new generating units, about 16% from loss reduction programs and the balance 30% from the rehabilitation of old generating units (see Table 4.4). Kazakhstan would contribute 45% of the incremental supply, followed by Uzbekistan and Tajikistan (22% each) and the Kyrgyz Republic (9%). Appendix 4.2 contains a more detailed set of information for each country and for the different years.

4.15 In addition to these supply increases, the Kyrgyz Republic and Tajikistan have some additional options to increase availability of electricity in winter from existing sources:

- In the Kyrgyz Republic, it is now possible to operate Toktogul cascade in a modified irrigation mode (see Chapter II) which will enable the release of an additional 1.5 BCM of water and thus generate an additional 1.5 billion kWh in the winter;
- In Tajikistan it is possible to shift the heat demand away from electricity to other resources (coal, gas, biomass), which is expected to make available roughly 860 GWh to meet electricity demand.

Table 4. 4: Composition of the Annual Incremental Supplies

Country	Incremental Supply (GWh) resulting from Projects Relating to:			
	Loss reduction	Generation Rehabilitation	New Generation	Total
Kazakhstan	5843	28401	6850	41,094 45%
The Kyrgyz Republic	1612	-	8509	10,121 11%
Tajikistan	1,988 +860	-	16830	19,678 22%
Uzbekistan	4064	-1489	17062	19,637 22%
Total	14,367 16%	26,912 30%	49,251 54%	90,530 100%

Note: The negative number in column 3 above indicates reduction in generation due to retirements in Uzbekistan. Also 860 GWh is gained in Tajikistan due to replacement of electricity for heating in winter by other energy sources.

C. Demand and Supply Balance and Export Potential

4.16 The supplies for each country for each year during the period 2005-2025 (from existing level of supply, the incremental generation coming on stream and retirement of old generating units) are compared to the projected demand in Table 4.5 The results indicate that in 2005 there would an annual surplus 7.4 TWh. Once the new investments start yielding, the regional surplus would rise to 43.4 TWh in 2020. Towards 2025, surpluses would drop back to 16.5 TWh, as demand growth outstrips supply growth. All countries except Uzbekistan have a deficit in winter currently. With the new projects, the largest surpluses come from Uzbekistan (2015) and Tajikistan (2020).

4.17 The picture is different when variations between summer and winter conditions are considered. In the winter of 2005 the region as a whole has a shortage of 1.6 TWh (2% of winter demand), but these deficits would be turned around as new investments start yielding output. The winter surplus in 2010 amounts to 6.9 TWh and it rises to 15.5 TWh by 2020. New capacity may be needed to meet winter demand towards 2025. The Kyrgyz Republic would be able to meet its winter demand (and therefore annual demand) through 2020, without Kambarata I and II, but with Bishkek II. Kazakhstan faces winter shortages but these shortages can be met through trade. Tajikistan would experience sizeable winter surpluses from 2010. Uzbekistan, however, has winter surpluses right through (see Table 4.5 and Figure 4.3).

Table 4. 5: Surplus Electricity Available for Trade (GWh)						
Country	Season	2005	2010	2015	2020	2025
Kazakhstan	Summer	3198	3623	6876	3745	-234
	Winter	-2504	-2969	-130	-5563	-12318
	Annual	694	654	6746	-1818	-12552
The Kyrgyz Republic	Summer	4737	6283	6863	6406	5991
	Winter	-2092	1584	1517	5761	4753
	Annual	2645	7866	8381	12167	10744
Tajikistan	Summer	1511	4587	6767	12579	11697
	Winter	96	2841	4287	8308	7431
	Annual	1607	7429	11055	20887	19128
Uzbekistan	Summer	1620	3904	7635	5088	2091
	Winter	2862	5485	9846	7058	3767
	Annual	4482	9389	17481	12147	5858
All Four Countries	Summer	11066	18396	28142	27819	19545
	Winter	-1637	6942	15521	15564	3633
	Annual	9429	25338	43663	43383	23178

4.18 It should be borne in mind that this is an indicative analysis intended only to provide a broad understanding of the potential for exports. Further meaningful analysis would be possible when the simulation of the systems are done both in energy and capacity terms (taking into account the daily and seasonal variations in demand both in the producing and importing markets). This is likely to be undertaken during the second phase of this study.

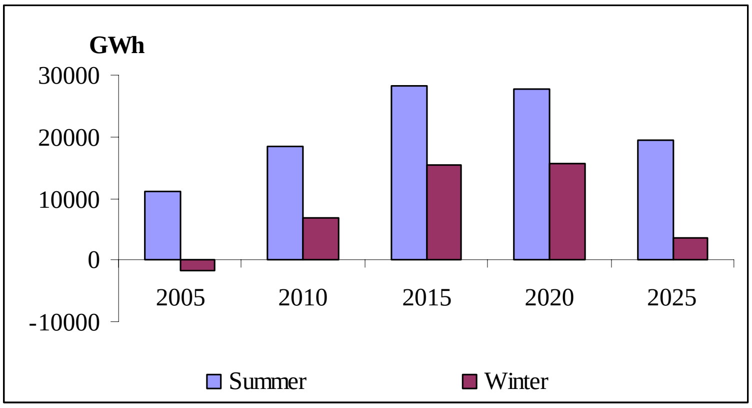


Figure 4.4: Central Asia Export Surpluses

Economic Assessment of Loss Reduction and Generation Rehabilitation Investments

4.19 A major portion of the projected demand in the CARs can be met with loss reduction and generation rehabilitation. The investments needed in transmission and distribution for loss reduction and in generation rehabilitation in the CARs is summarized in Table 4.6. Investment needs in the Kyrgyz Republic and Tajikistan are in transmission and distribution for technical loss reduction projects, whereas in Kazakhstan and Uzbekistan investment in generation rehabilitation are also needed in addition to those in transmission and distribution. Accordingly, these two countries account for 90% of the investments needs in the region.

Table 4. 6: Investment in Loss Reduction and Generation Rehabilitation in CARs (US$ million)

Investment Project	2004-2005	2006-2010	2011-2015	2016-2020	2021-2025	2004-2025	AIC (c/kWh)
Kazakhstan							
Transmission and Distribution	324.0	972.0	0.0	0.0	0.0	1296.0	2.8
Ekibastuz GRES-1 Rehabilitation	0.0	308.0	132.0	0.0	0.0	440.0	2.65
Other Large and Medium Units Rehabilitation	0.0	395.9	460.1	214.0	0.0	1070.0	2.75
Kazakhstan Total	324.0	1675.9	592.1	214.0	0.0	2806.0	2.8
The Kyrgyz Republic							
Transmission and Distribution	50.0	200.0	0.0	0.0	0.0	250.0	2.3
The Kyrgyz Republic Total	50.0	200.0	0.0	0.0	0.0	250.0	2.3
Tajikistan							
Transmission and Distribution	25.0	285.0	0.0	0.0	0.0	310.0	2.1
Tajikistan Total	25.0	285.0	0.0	0.0	0.0	310.0	2.1
Uzbekistan							
Transmission and Distribution	172.9	691.8	288.2	0.0	0.0	1153.0	3.5
Rehabilitation of Existing Generation	87.0	522.0	246.8	80.7	213.5	1150.0	3.6
Uzbekistan Total	259.9	1213.8	535.0	80.7	213.5	2303.0	3.5
CARs Grand Total	658.9	3374.7	1127.1	294.7	213.5	5669.0	

4.20 Table 4.6 also summarizes the impact of the investments in loss reduction and generation rehabilitation on the cost/kWh of electricity for individual investment schemes as well as for the respective systems. As shown, these investments would result in a system average incremental costs/kWh (in 2004 prices) of 2.1 cents in Tajikistan; 2.3 cents in the Kyrgyz Republic; 2.8 cents in Kazakhstan and 3.5 cents in Uzbekistan. Details are provided in Appendix 4.1.

CHAPTER V: ASSESSMENT OF NEW GENERATION OPTIONS

5.01 This chapter would try to answer the following set of questions: what are the economic and financial costs of the electricity generated from the new generation projects? What would be the transmission costs for the power to understand the landed cost of power in the target markets? How competitive would the landed power from CARs be in these target markets?

A. Technical Assessment

5.02 A summary of physical and technical parameters of the new projects under consideration in Central Asia[20] is provided in Table 5.1. All projects, except Kambarata I and the New Ekibastuz Thermal Plant, are partly constructed. Of these, Talimardjan is the most advanced (requires only one year to complete) and Kambarata II is the least advanced.

Table 5. 1: Physical and Technical Details of New Generation Projects

Project	Country	Type	Capital Costs ($ million)	First Year of Output	Capacity MW	Steady State Generation (GWh)	Steady State Sales (GWh)
Sangtuda I	Tajikistan	Hydro (Run-of-River)	370	2009	670	2,700	2,673
Rogun I	Tajikistan	Hydro (Storage)	785	2014	1,200	4,690	4,643
Rogun I&II	Tajikistan	Hydro(Storage)	$2,455	2014	3,600	14,300	14,157
Kambarata I	The Kyrgyz Republic	Hydro (Storage)	1,940	2017	1,900	5,100	5,049
Kambarata II	The Kyrgyz Republic	Hydro (Run-of-Rover)	280	2012	240	1,116	1,105
Bishkek II	The Kyrgyz Republic	Thermal Gas CCGT	196	2007	400	2,453	2,355
Talimardjan I	Uzbekistan	Thermal Gas fired Steam	100	2005	800	4,537	4,265
Talimardjan II	Uzbekistan	Thermal Gas fired Steam	1,200	2011	2,400	13,613	12,796
Ekibastuz Rehabilitation	Kazakhstan	Thermal Coal Fired Steam	440	2010	2,000	12,264	11,283
New Ekibastuz Plant	Kazakhstan	Thermal Coal Fired Steam	1,085	2020	1,000	7,446	6,850

5.03 In terms of planned installed capacity Rogun I and II together would be the largest, at 3,600 MW, followed closely by both phases of Talimardjan in Uzbekistan, which would have a capacity of 3,200 MW. Partly due to its advanced state of construction, and partly due to the fact that the capital costs of thermal projects would be lower than for hydro projects, Talimardjan I has the lowest capital cost per kW of installed capacity, followed by Ekibastuz rehabilitation. In terms of electricity output, the Talimardjan scheme would have the highest output of 18,150 GWh, which represents a plant factor of about 65%. This plant factor could be higher (e.g. 85%), but there are technology issues[21] and gas reserves issues[22], which are likely to keep the plant

[20] The list also includes rehabilitation of the 4 x 500 MW units at Ekibastuz I plant owned by US based AES, as this company has plans to rehabilitate and add substantial capacity at this location, assuming markets exists

[21] Though each unit will have a nameplate capacity of 800 MW, the maximum plant factor is expected to be 65% only based on technical/operational experience in a few similar operating units in the former Soviet Union. Further, cooling water availability is a limiting factor for the first unit. Before proceeding with the three new units arrangements for additional water supply must be firmed up.

[22] The plant is located at the Mubarek gas field, which is a reasonably large field. However, the field has been producing for more than 15 years now, there has not been an independent audit of the reserves to know what is the remaining recoverable reserves from this field.

factor low. Rogun would have the next highest output of 14,300 GWh[23], representing a plant factor of about 45%. This is rather high for hydro projects (which are typically in the 20 to 30% range) and reflects the assumed nature of the glacier-melt and snow-melt fed water flows in the Vaksh River, which currently average 20 BCM annually. The rehabilitated Ekibastuz I plant would be the third largest producer, with an annual output of 12,300 GWh, i.e., at a plant factor of 70%, typical for a coal-fired steam power plant.

5.04 Time needed to complete the remaining works and commission the plant would be the lowest for Talimardjan I followed by Bishkek II, which would require a year to prepare and two years to construct. The smaller hydro scheme at Sangtuda I, which is essentially a run-of-the-river scheme, could be completed in 4 years and could come online in 2009. The larger storage hydro schemes, Rogun and Kambarata I, would require a longer preparation time, typically 4-5 years, and a long construction time, typically 7 years. These large storage hydropower schemes on international rivers would need time to sort out environmental and riparian issues. Accordingly, it is estimated that the first units from Rogun could be put into operation in 2014, and those from Kambarata I in 2017. Kambarata II could come on stream in 2012, though its construction ahead of Kambarata I has to recognize certain risks [24]. The new thermal power plants, Talimardjan II and the New Ekibastuz Plant, could come on stream after the rehabilitation of existing thermal plants. Accordingly, Talimardjan II construction could start in 2009 and the new units would commence generation in early 2011. The New Ekibastuz Plant construction could start in 2016 and units would be put into operation from 2019 onwards.

B. Economic Assessment

(i) Economic Cost of Generation

5.05 Based on the above technical parameters, the economic costs of output from each of the new projects are derived, as summarized in Table 5.2. The details of the computations are given in Appendix 5.1, including annual phasing of capital expenditures, fuel costs (where applicable), operation and maintenance (O&M) costs, as well as the energy sent out from the generating station (i.e., gross energy generated minus station use or auxiliary consumption). For projects partly constructed, capital costs shown are for completing the remaining works needed to commission the unit (i.e., sunk costs are not taken into account). For Kambarata I and the New Ekibastuz Thermal plant for which no cost has so far been incurred, full construction costs have been taken into account. All costs are stated in constant 2003 dollars.

5.06 Talimardjan I would have the lowest economic output costs, reflecting minimal incremental capital costs and a short construction timeframe. Sangtuda I has the next lowest output cost, followed by Bishkek II, reflecting the smaller capital outlays (compared to new projects of similar size), shorter construction period. From a Central Asian perspective, much of Sangtuda I's generation (60%) is in the summer, when there are already surpluses in Tajikistan

[23] When combined with the additional generation of 1,300 GWh at Nurek.
[24] It is essentially a run-of-the river plant with very little storage and generates only in the summer, when there is already surplus electricity. Also, without Kambarata I, the sedimentation problems could become severe calling for expensive solutions.

as well as elsewhere in the region, but the thermal projects can generate electricity throughout the year, especially in winter, when there are shortages.

5.07 Among the large hydro schemes, Kambarata I would have the highest economic output price of 7.17 cents/kWh and is therefore the least attractive. Compared to Rogun, Kambarata's cost/kW installed is about 50% higher (US$1,021 compared to US$682) and its plant factor is much lower (31% compared to 41%). Rogun I would be able to generate power after five years of construction while Kambarata I will take eight years of construction before it could generate power. Further, Rogun also benefits from the fact that when it is built, the generation at the downstream Nurek reservoir would also increase.

Table 5. 2: Comparison of Economic Cost of Supply with Marginal Costs in Exporting/Importing Countries and Status of Cost Competitiveness

New Project	Economic Cost/kWh from the New Project	National system Marginal Cost /kWh without the New Project	Marginal Generation Costs in the Target Export Markets (cents/kWh)				
			Afghanistan	Iran	Pakistan	Russia	China
			3.7	3.56	5.6	3.0	3.6 to 4.0
Sangtuda I	1.97	2.1	yes	yes	yes	yes	yes
Rogun I	2.46	2.1	yes	yes	yes	yes	yes
Rogun I&II	2.83	2.1	yes	yes	yes	yes	yes
Kambarata I	7.17	2.3	no	no	no	no	no
Kambarata II	3.72	2.3	no	no	yes	no	no
Bishkek II	2.55	2.3	yes	yes	yes	yes	yes
Talimardjan I	1.68	3.5	yes	yes	yes	yes	yes
Talimardjan II	2.76	3.5	yes	yes	yes	yes	yes
Ekibastuz I Rehabilitation	2.65	2.8	yes	yes	yes	yes	yes
New Ekibastuz Plant	4.54	2.8	no	no	yes	no	no

5.08 The economic analysis determined the economic cost/kWh for each generation option at a discount rate of 10%. What this also implies is that if the output could be sold in the domestic or export markets at higher prices the internal Rate of Return would be higher than 10%. A comparison is also made in Table 5.2 between the economic output costs from the new projects and: (a) the average prices needed to recover the incremental costs of the relevant national power system without the new projects[25]; and (b) the estimated marginal generation costs in the target export markets.

5.09 The above table helps to judge, broadly whether the projects are reasonable economic choices in the national, regional and export electricity markets. Electricity from projects like Sangtuda I, and Talimardjan I and II have economic costs actually lower than the average incremental costs of their national systems[26], and therefore these projects make sense as good capacity additions to the national grids if the incremental demand warrants such capacity addition. Actually, most of the projects except Kamabarata I and the New Ekibastuz Plant seem to be economic choices, purely based on generation cost consideration. Later in this chapter,

[25] The incremental cost referred to here consists of investment costs, fuel, O&M costs of rehabilitation of generation, transmission and distribution, including loss reduction.
[26] That is, average incremental costs of national system before the construction of these projects.

competitiveness analysis is carried out which considers costs of transmitting central Asian power to target market.

C. Financial Assessment

5.10 The financial analysis is carried out to understand the financial cost of supply of electricity from each of the new supply options. A corporate finance approach is taken where it is assumed that each of these options would be developed as an independent power producer with private sector participation. Also, to enable comparability, a consistent set of assumptions is applied as regards financing structure, cost of capital etc.

5.11 The estimated costs used for the economic analyses (Table 5.1) are converted to nominal values and interest during construction (IDC) is considered to arrive at the financing needed for each project. The financing of each of these projects is based on a structure that would result in a post IDC financing structure of roughly 25% equity and 75% debt. This structure brings a balance between the lenders' views (assurance that the debt service is adequately covered from annual net revenues) and investors' views (minimize equity, also because equity is often costlier than debt which would drive up the output costs). The terms of debt assumed are an interest rate of 10%, a repayment period of 15 years including a five year grace period. The equity is expected to earn an internal rate of return (IRR) of 15% over the life of the investment, which translates to an annual rate of return on equity in the range of 17% to 24% in respect of these projects[27]. On this basis, the tariff/kWh required to service the debt and provide the return on equity for each year is computed for a 20-year period. These annual tariffs are then levelized[28] to enable comparison among different financing options (for a given project) or among different projects. Such levelized tariff/kWh for the projects are summarized in Table 5.3.

Table 5. 3: Levelized Tariffs for Generation Options

Project	Electricity output GWh	Levelized Tariff Cents/kWh
Sangtuda I	2,673	2.44
Rogun I	4,643	2.91
Rogun I &II	14,157	3.24
Kambarata I	5,049	8.54
Kambarata II	1,105	3.95
Bishkek-II	2,355	2.67
Talimardjan I	4,265	1.75
Talimardjan II	12,796	2.92
Ekibastuz Rehabilitation	11,283	2.66
Ekibastuz New	6,850	5.05

[27] The level of annual Return on Equity varies among the projects, largely, as a function of the construction period. Longer construction periods make the investors wait for longer periods for cash inflows and thus raise the annual equity returns to achieve a 15% IRR on equity over the life of the investment.

[28] Levelized tariffs are the smoothened tariffs for the whole period under consideration. It is a single tariff figure and it implies that the present value of the cash flow generated from the application of levelized tariff will be the same as the present value of the cash flow generated through the application of the actual tariff, which usually varies, sometimes significantly, from year to year.

5.12 As can be seen, the financial output costs are consistent with the economic costs analyses, in that Talimardjan I remains the most attractive, and Kambarata I the least.

D. Sensitivity Analysis

5.13 Sensitivity analyses are carried out on from both economic and financial perspectives, to understand how the changes in key variables impact output costs.

Economic Sensitivity Analyses

5.14 The above economic output costs assume that all the production from these new projects would be sold (either in the domestic market or in the export markets). However, it is possible that sometimes, not all of the power generated would be consumed. Therefore, a sensitivity analysis has been performed on each of the projects to understand the extent of impact on output costs, under different plant factors, and the results, in what are known as Screening curves, are shown in Figures 5.1 and 5.2.

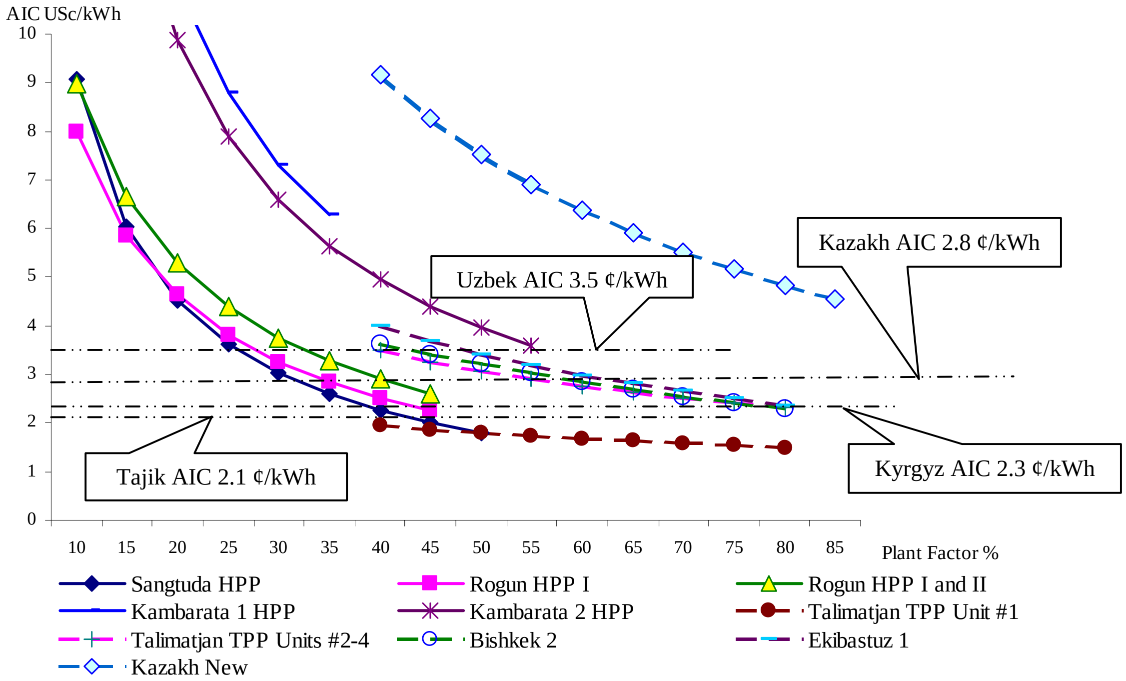


Figure 5. 1: Economic Output Costs of New Projects at different Plant Factors Vs. Average Incremental Costs of National Systems of CARs

5.15 The curves in Figure 5.1 compare the economic output costs of power from the new projects at different plant factors with the average incremental costs of each system before the construction of the new projects. This indicates the limits of plant factors at which the marginal costs from the new projects remain conducive to internal trade within the CARs. As the plant factor is lowered, the volume of generation declines and the economic cost of output/kWh rises. Rates of such rise are notably lower in the case of thermal projects than in the case of hydro projects. A combination of these graphs and the marginal cost data of export markets give us an indication of the range of demand within which these projects remain economic in the export markets (See Figure 5.2).

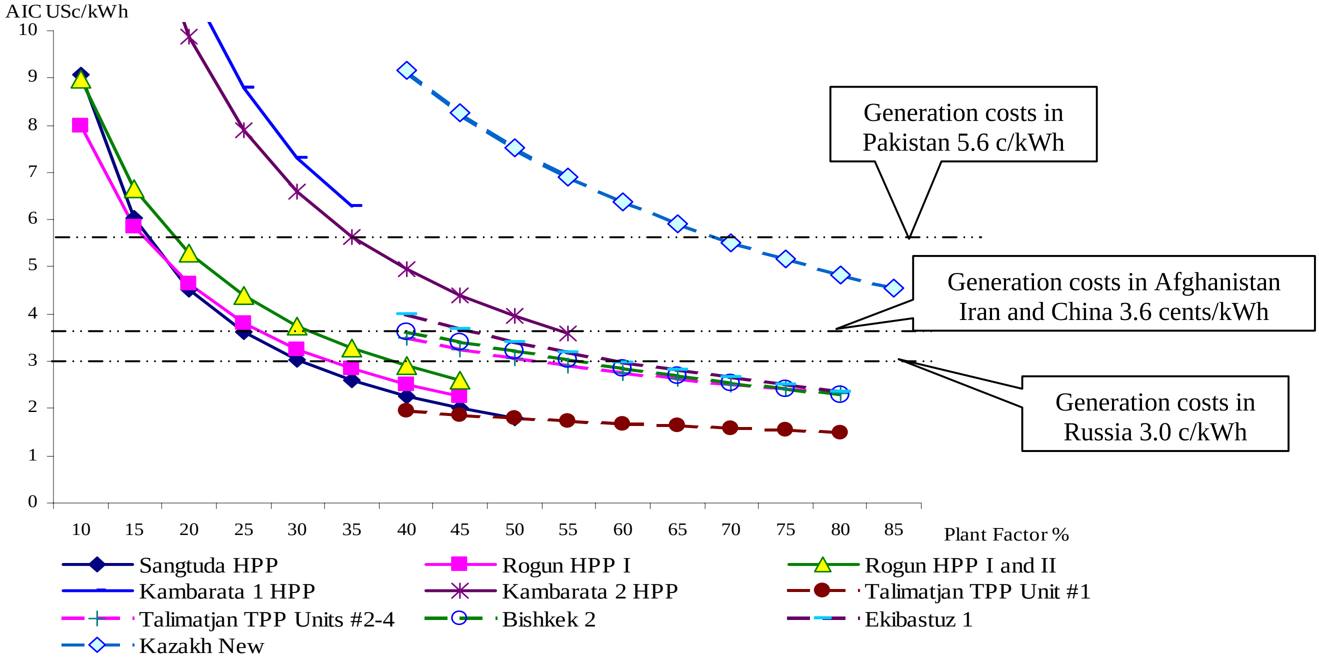


Figure 5. 2: Economic Output Cost of New Projects at Different Plant Factors Vs. Generation costs in Target Markets (Excluding Transmission Cost)

Financial Sensitivity Analyses

5.16 Sensitivity analysis on the financial assessments has been carried out for decreases in generation, for increases in capital expenditures, fuel cost, interest rate and rates of return on equity. The results are summarized in Table 5.4. Given the high cost per kW, long preparation and construction times and low load factors, the hydropower projects are much more sensitive to changes in respect of most parameters, than thermal power projects. Accordingly, unless firm export contracts are in place it would not make sense to invest in these projects. Thermal power projects would be able to deal with possible reductions in export demand much better than the hydro projects. However, thermal projects are also quite sensitive to fuel price increases. The high sensitivity value for fuel price changes for Talimardjan I is due to the fact that the considered capital costs is very small, since a large portion of it is sunk cost.

Table 5. 4: Results of Sensitivity Analyses on Levelized Tariffs of Generation Projects						
Project	Base Case Levelized Tariff Cent/kWh	Percentage change in levelized tariff when there is				
		1.0% decrease in Generation	1.0% increase in Capital Expenditure	1.0% increase in Interest Rate*	1.0% increase in Return on Equity**	1.0% increase in Fuel Cost
Sangtuda I Hydro	2.44	1.25%	0.97%	0.70%	0.42%	..
Rogun I Hydro	2.91	1.25%	0.99%	0.71%	0.45%	..
Rogun I &II Hydro	3.24	1.25%	0.89%	0.79%	0.49%	..
Kambarata I Hydro	8.54	1.25%	1.00%	0.82%	0.52%	..
Kambarata II Hydro	3.95	1.25%	0.99%	0.38%	0.46%	..
Bishkek-II	2.67	0.83%	0.46%	0.30%	0.21%	0.34%
Talimardjan I	1.75	0.37%	0.17%	0.09%	0.04%	0.71%
Talimardjan II	2.92	0.81%	0.59%	0.47%	0.31%	0.17%
Ekibastuz Rehab	2.66	0.63%	0.23%	0.18%	0.12%	0.50%
Ekibastuz New	5.05	0.60%	0.59%	0.46%	0.50%	0.29%

*1% of 10% or 10 basis points;
**1% of assumed rate of return (17 basis points if the RoE is 17%).

E. Competitiveness Assessment

5.17 From the previous sections it appears that Central Asian power, including several of the new projects, could be competitive in the target export markets. However, to gain a better understanding of competitiveness, it is necessary to consider the landed costs of Central Asian power in the target markets and therefore the costs of transmission from Central Asian grid (CAPS) to each of these target markets should also be considered.

Transmission Needs for Electricity Trade

5.18 On the face of it, it would appear that no major expansion of the grid is needed to accommodate power transfers from one part of the CAPS to the other since the electricity currently handled by the CAPS is currently 136 TWh (2003) compared to 184 TWh in 1990. However, this needs to be confirmed with studies of the present and projected load flows, and also an assessment of the condition of the network[29]. Nevertheless, one link that is considered strategic is the expansion of the North South transmission link in Kazakhstan to facilitate enhanced flows of power from north Kazakhstan to south Kazakhstan, and removal of bottlenecks for enabling exports to Russia. Part of this strategic link has already been funded by a recent EBRD loan. The funding and completion of the remaining sections of the this second link is of great importance to facilitate trade within CAPS and with its external market in Russia making full use of the large thermal plants in northern Kazakhstan for trade.

5.19 To supply power to markets other than Russia, new lines will be needed as shown in Figure 5.3 to complement the existing ones (which themselves need strengthening).

[29] This is planned to be carried out in Phase II of the Study.

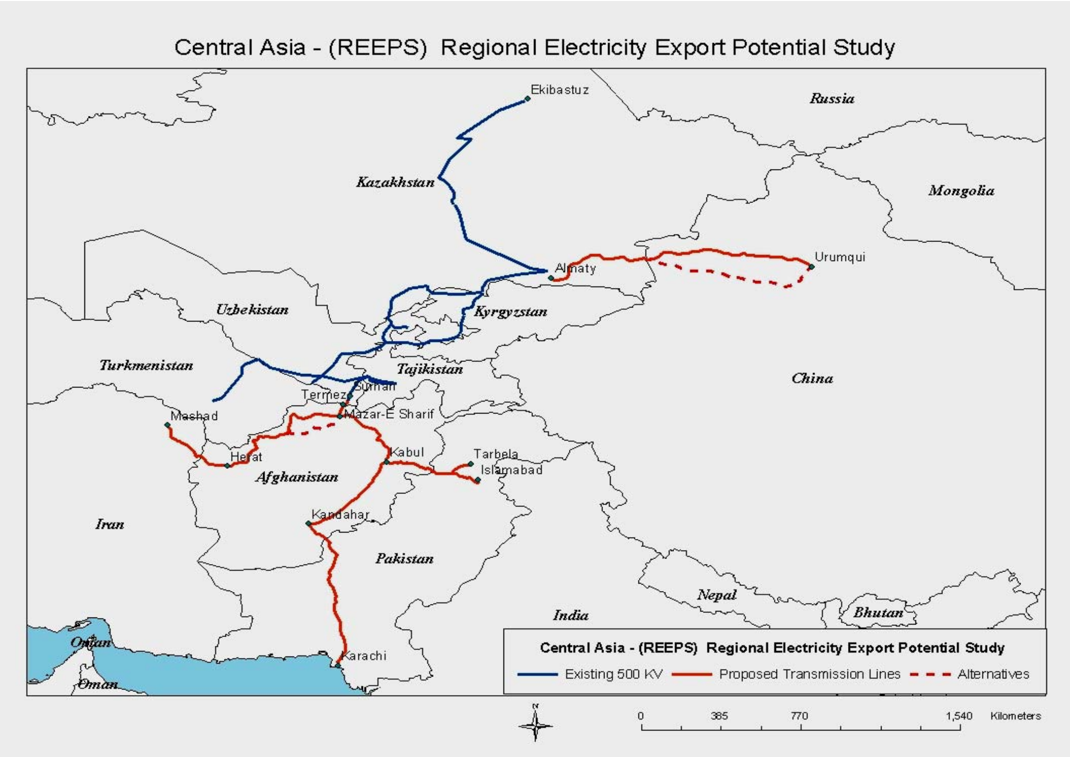


Figure 5. 3: New Transmission Lines Needed For Exports

5.20 Mazar-e-Sharif in Afghanistan, which is linked from Tajikistan and Uzbekistan (as well as Turkmenistan), has the potential to become a key node in northern Afghanistan to enable power transfers between Central Asia and Afghanistan, Iran and Pakistan. The line between Central Asia and Iran via Afghanistan would follow the Central Asia – Mazar-e-Sharif - Herat (in western Afghanistan) route to where Iran is already constructing a 220 kV line from its network. Central Asia to Pakistan lines could follow the Central Asia – Mazar-e-Sharif – Kabul routing and then possibly to Tarbela in Pakistan. Alternatively, it could pass through Khandahar in southern Afghanistan and reach Karachi (via Quetta in western Pakistan). For exports to China, the optimal routing appears to be Almaty to Urumqui in the Xinxiang province. All the proposed new lines are considered to be double circuit 500 kV AC transmission lines with associated substations, with the exception of the Almaty –Urumqui line which would be built as a 500 KV DC line with back to back converters.

5.21 Following a methodology similar to that adopted for generation projects, the economic and financial analyses of the transmission links are undertaken and the transmission cost/kWh in respect of these lines have been arrived at (see Appendix 5.2 for details). The results are summarized in Table 5.5.

Table 5. 5: Economic and Financial Analysis of Transmission Options									
Line	Distance km	Voltage kV	Line type	Annual transm. GWh	Number of new substations	Number of substations expansion	Investment US$ million	Economic cost of transm. Cents/ kWh	Financial cost of transm. Cent/kWh
Almaty (Kazakhstan) - Urumqui (China)	1,050	500	DC	10,000	1	1	390.0	0.66	0.72
Surhan (Uzbekistan) - Kabul (Afghanistan)	515	500	AC	5,000	2	1	153.0	0.43	0.51
Kabul (Afghanistan) - Tarbela (Pakistan)	360	500	AC	3,000	1	1	90.5	0.44	0.49
Surhan (Uzbekistan) - Mashad (Iran)	1,150	500	AC	10,000	4	1	320.0	0.53	0.59
Optional Lines									
Kabul (Afghanistan) - Kandahar (Afghanistan)	490	500	AC	5,000	2	1	138.2	0.40	0.46
Kandahar (Afghanistan) - Karachi (Pakistan)	900	500	AC	4,000	3	1	226.6	0.84	0.99

Competitiveness of Central Asian Electricity

5.22 The marginal generation costs in the target markets have been compared to the landed costs (generation costs of each envisaged projects in the CARs plus associated transmission costs) and the results are summarized Table 5.6. Sangtuda I in Tajikistan and Talimardjan I in Uzbekistan are likely to be competitive in all markets, where as Rogun I and Talimardjan II would be competitive in Afghanistan, Iran and Pakistan. In Pakistan, Rogun phase II as well as Kambarata II could also be competitive.

Table 5. 6: Marginal Costs of Generation in Target Markets versus Import Costs (cents/kWh)				
Target Market	Marginal Generation Cost in Target Market	Supply Options	Transmission Cost	Total Landed Cost of Imports
Afghanistan	3.7	Sangtuda I, Rogun I, Talimardjan I and II	0.51	2.26 – 3.43
Iran	3.6	Sangtuda I, Rogun I, Talimardjan I and II	0.54	2.29 – 3.46
Pakistan	5.6	Sangtuda I, Rogun, Talimardjan I and II, Kambarata II	0.51	2.26 – 3.75
China	3.6	Sangtuda I, Talimardjan I	0.72	2.47 – 3.16
Russia	3.0	Sangtuda I, Talimardjan I	0.55	2.30 – 2.99

Key Conclusions

5.23 It would perhaps be useful to recapture the key points from the discussions on demand/supply from the previous chapter, as well as the in-depth analysis of the supply options from this chapter:

i. Annual domestic demand in the Central Asian Republics can be met roughly until about 2020 through the implementation of loss reduction measures, the rehabilitation of existing generation capacity; and complementary measures such as modified irrigation operation of Toktogul reservoir in the Kyrgyz Republic and shifting the demand for space heating in Tajikistan away from electricity.

ii. Seasonal supply shortages in the winter will persist. The most cost effective option to meet this shortfall will be to trade at the margin. However, since there is a shortage of capacity in winter, some new generation will be needed to meet winter demand requirements.

iii. The most attractive new generation options to meet the winter demand requirements are the Talimardjan Thermal Power I Project in Uzbekistan that is largely complete, and the Bishkek II Thermal Power Project in the Kyrgyz Republic, which is partially constructed. The Bishkek II Thermal Power project represents a more cost effective and quicker option to meet the Kyrgyz Republic's future requirements than the Kambarata hydropower projects in the Kyrgyz Republic. These two thermal power plant projects, however, are both dependent upon the availability of gas in Uzbekistan.

iv. In addition, some upgrading of the transmission facilities will be required to facilitate intra-regional trade, including the construction of the North South Line in Kazakhstan, and addressing any transmission bottlenecks in the southern part of the Central Asian grid.

v. These additional transmission investments and generation capacity also make sense from an extra-regional perspective. In addition, the Sangtuda I hydroelectric scheme, which is quite competitive and makes some contribution to meeting winter demand, should also be considered a strategic investment with regional implications.

vi. Increased intra-regional trade will provide significant benefits. In addition to enabling the CARs to meet their respective demand at least costs. Uzbekistan, for example, can optimize seasonal fuel mix, conserve gas, benefit the environment, and perhaps even qualify for carbon emission credits.

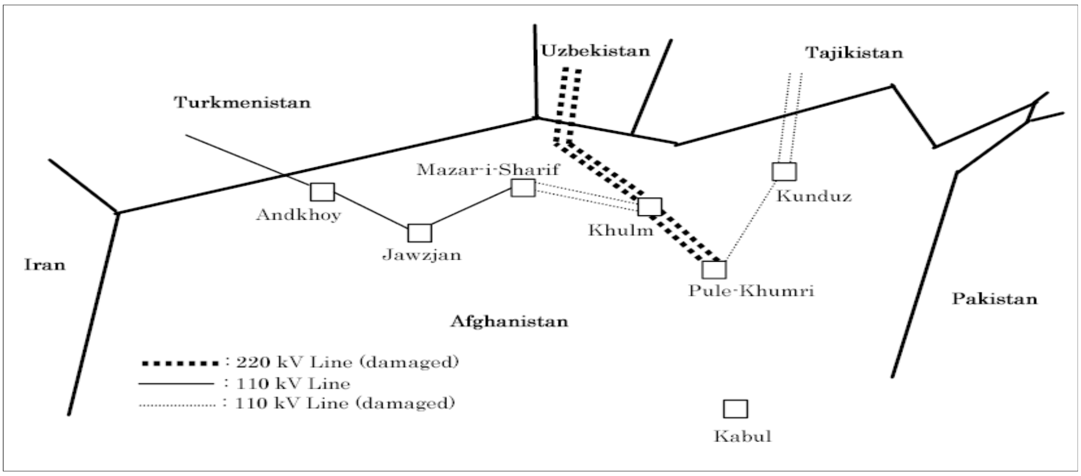
vii. Major new generation projects in Central Asia, such as Rogun and Talimardjan II, will be feasible only if there is assured access to export markets outside the region. In this regard, electricity from Central Asia has the potential to compete in cost terms with marginal generation costs in each of the targeted markets outside the region. However, the cost advantage is not overwhelming, and may not be sufficient to overcome security of supply concerns.

CHAPTER VI: PROFILE OF THE POTENTIAL EXPORT MARKETS

A. Afghanistan

6.01 ***Infrastructure:*** Afghanistan has considerable energy resource endowments but uncertainty exists about the extent of the resources. Its fossil fuel resources are thought to comprise: some 30 billion cubic meters of gas reserves, 95 million barrels of oil and condensate reserves; and coal reserves in excess of 100 million tons based on historical geological reserves estimates. However, engineering, costs and market analysis work is needed to improve upon these reserves estimates and evaluate how much of these can be commercially exploited. Afghanistan also has considerable amount of hydroelectric potential. On account of the series of prolonged conflicts, the energy infrastructure of Afghanistan could not grow beyond the level at which it was in the mid 1970s and had in fact considerably deteriorated on account of war damages. As of 2003, its installed electricity generation capacity is reported to be 454 MW, while its operable capacity is believed to be only 285 MW[30]. There is no national electricity grid, and the system is made up of three isolated systems centered around the cities Kabul, Kandahar and Mazar-e-Sharif. The largest system is the one in Kabul, with installed capacity of 245 MW (200 MW Hydro and 45 MW diesel fired gas turbine). The hydroelectric units have a firm power output of only 65 MW, thus making electricity shortages more acute in winter.

6.02 The Afghan power system is connected to those of its northern neighbors, the Central Asian Republics of Tajikistan, Turkmenistan, and Uzbekistan, as shown in Figure 6.1. There is also a relatively small link (20 kV single current, between Zabol in Iran and Zaranji in Afghanistan) with Iran in the Herat area. In addition, 132 kV double circuit line from Tobat-e-Jam in Iran to Herat (a 150 km distance) is in operation.



Source: Asian Development Bank - Study for Power Interconnection for Regional Trade, March, 2003.

Figure 6. 1: Afghanistan's Cross-Border Electricity Interconnections

[30] Electricity Sector Policy, Ministry of Water and Power, Afghanistan, August 2003.

6.03 Efforts are underway to strengthen and increase the interconnections, and some of these efforts are more concrete than others. The line between Turkmenistan and Herat was completed with Afghan government funds in May 2004. This line is built at 220 kV, but is currently operated at 110 kV. In addition, ADB will be financing the repair and reconstruction of the Termez (Uzbekistan) to Phul-e-Khumri and this will be a 241 km long two parallel single circuit lines.

6.04 ***Current Demand*** : The recently completed Power Sector Master Plan for Afghanistan estimates that the current demand is about 750 GWh and the present peak load is assumed to be 215 MW for all of Afghanistan. There may also be a suppressed demand, which is assumed to be 470 GWh in energy terms and 121 MW peak power needs.

6.05 ***Consumers and Consumption***: A very low level of access to electricity is the most urgent energy issue in Afghanistan. Only 234,000 consumers in the country are connected to the electricity network. More than 202,000 of them were residential consumers. The grid around Kabul caters to about 76,000 consumers. On the whole only about 6% of the population have access to the electricity network. With the lack of generation capacity, even those connected to the grids do not enjoy reliable power, results in a per capita power consumption of only 16 kWh/year[31], perhaps the lowest figure in the world.

6.06 ***System Loss and Collection***: Given the damaged state of the transmission and distribution facilities, the transmission and distribution losses were estimated at 25% in 2002. In addition the non-technical losses in the distribution system were estimated at 20%. Thus 45% of the electricity generated is lost and does not get billed. Only about 54% of the value of the bills issued are actually collected.

6.07 ***Costs of Supply***: Different parts of the Afghan power supply system incur varying levels of costs based on sources of power supply (hydro, thermal, imports etc), the density of the population and the extent of coverage of this population. As such, the Kabul area has the lowest costs of supply, (since it has the highest proportion of hydro-based supply, and more than 50% of the customer base is located here) followed by the Balkh, Kunduz and Herat areas.

6.08 ***Present Imports of Electricity*:** Afghanistan imports electricity from Iran, Uzbekistan, Tajikistan and Turkmenistan. . The information on current electricity imports is summarized in Table 6.1.

Table 6. 1: Current Electricity Imports by Afghanistan

	Iran	Tajikistan	Turkmenistan	Uzbekistan
Duration of Contract (years)	4	1	10	1
Maximum Capacity (MW)	2 MW (Nimroz); 2MW (Herat)	Winter - 5 MW; Summer - Unlimited	2 MW (Herat); 6 MW (Andkhoy)_	150
Maximum Energy (million kWh)	NA	NA	15 million kWh	NA
Price (US cents/kWh)	2.25	2	2	2

Source: Afghanistan Ministry of Water and Power .

31 ADB Appraisal Report (No. AFG 36673) on Emergency Infrastructure Rehabilitation and Reconstruction Project, May 2003.

6.09 The Protocol of Intentions between Afghanistan and Uzbekistan says that Uzbekistan will provide up to 150 MW for a 10-year period at a cost of 2.0 US cents/kWh for the first year. There are issues of payment by Afghanistan for its power imports – Uzbekistan is owed funds for past supplies.

6.10 ***Projected Electricity Demand***: The recently completed Power Sector Master Plan for Afghanistan also projects the demand for the 2020 period, which is summarized in Table 6.2.

Table 6. 2: Afghanistan – Summary of Energy Demand (GWh) and Peak Load (MW) Forecast

Region	Present Load		Suppressed Demand		Forecast Basis		Basic		Low		High	
	Demand	Peak Load	Demand	Peak Load	Demand	Peak Load	Demand	Peak Load	Demand	Peak Load	Demand	Peak Load
Kabul	359	111	212	55	571	166	1522	347	1047	239	2133	487
Nangarhar	49	8	9	5	58	13	260	54	176	36	374	78
Parwan	1	2	30	6	31	8	166	38	105	24	248	57
Ghori	28	14	75	12	103	26	358	80	248	55	604	129
Balkh	149	38	52	13	201	51	680	155	432	99	969	221
Herat	1	2	36	8	37	10	325	74	196	45	509	111
Kandahar	141	30	43	12	184	42	431	90	292	61	625	130
Other	22	10	13	10	35	20	126	67			175	92
Total	750	215	470	121	1220	336	3868	905			5637	1305

Source: Power Sector Master Plan for Afghanistan, 2004

6.11 In the Basic Forecast the energy demand is assumed to reach 3,868 GWh in the year 2020. This gives an average annual growth rate of 6.6% from the forecast basis (including suppressed demand) and 9.5% from the present (2002) load. In the High Forecast the energy demand is assumed to reach 5,636 GWh in the year 2020. This is 46% higher than the Basic Forecast and implies an average annual growth rate of 8.9% from the forecast basis (including suppressed demand) and 11.9% from the present (2002) load.

6.12 ***Institutional and Financial Aspects.*** Da Afghanistan Brishna Moassesa (DABM) is a state-owned vertically integrated utility that operates all the power facilities in Afghanistan. It is subject to supervision by the Ministry of Water and Power.

Table 6. 3: Current Electricity Tariffs in Afghanistan

	Kabul		Balkh		Kunduz		Herat	
Category	Afs/kWh	USc/kWh	Afs/kWh	USc/kWh	Afs/kWh	USc/kWh	Afs/kWh	USc/kWh
Residential			2.0	4.1	2.5	5.1	4.0	8.2
0-600 kWh/month	0.5	1.0						
600-1200 kWh/month	1.6	3.3						
Above 1200 kWh/month	2.5	5.1						
Government	5.0	10.2	5.5	11.3	5.0	10.2	7.0	14.3
Other Consumers	5.0	10.2	5.5	11.3	5.0	10.2	7.0	14.3
Foreign NGOs etc.	5.0	10.2	6.0	12.3	10.0	20.5	10.0	20.5

Source: Securing Afghanistan's Future Power Sector Technical Annex, December, 2003

6.13 The present tariff structure in Afghanistan is summarized in Table 6.3. Although the posted tariffs appear high compared to the affordability level in Afghanistan, the average bills incurred by the residential consumers tend to be much lower, since most consumers do not get anything more than 600 kWh a month, due to supply shortages.

6.14 ***Afghanistan's Emerging Power Supply Strategy***: Subsequent to the finalization of 'Securing Afghanistan's Future', the strategic document presented to the Donors in Berlin earlier this year, key elements of a strategy to meet electricity supply needs are beginning to emerge. These elements include, recognition that electricity imports are key to close the supply gap in the short term and imports would continue to play an important role in meeting power demand over time. The focus therefore in the short term is to address the problems of sub-optimal power purchase arrangements with Central Asian neighbors. In the medium to long term, Afghanistan would develop its own generation sources for strategic/developmental reasons, as well as one of energy security; and whether or not imports would constitute a serious option would depend on the availability of long term power priced competitively.

6.15 To sustain imports at least in the short term, Afghanistan has to ensure payments for the imported power, which is a challenge. In this regard, the Afghan authorities are willing to provide the exporting entities additional comfort regarding the payment obligations for power, most likely with support from international financial institutions (IFIs). This could possibly come from the Afghanistan Reconstruction Trust Fund (a multi-donor trust fund administered by the World Bank) although sufficient funds are not currently available. The ARTF is expected to be in place until 2010. Another alternative to consider could be a line of credit and/or guarantee from an IFI backstopping payment obligations.

6.16 ***Afghanistan as a Transit Country*:** Afghanistan has the potential to wheel power from the Central Asian Republics to Pakistan and to Iran via Herat, which is an important load center in Afghanistan. However, to be able to realize this potential, significantly more information and indications of serious interest on the part of all concerned would need to be available, and this may take some time

B. China

6.17 ***Infrastructure***: Xingjian province of China has a common border with the Central Asian Republics and could be a potential market for electricity exports. With a population of about 1.3 billion China has the second largest electricity industry in the world. Its total installed generation capacity at the end of 2002 was about 353 GW and total electricity generation in 2002 amounted to 1620 TWh. About 74% of the electricity generation is based mostly on coal and partly on gas. 24% is from hydroelectric stations. About 2% from nuclear power plants.

6.18 ***Market***: More than 95% of the settlements in China are believed to have access to electricity. Industries consume 72% of total electricity, followed by households (12%), Agriculture (5%) and others (11%).

6.19 ***Demand Growth and Outlook***: Though electricity demand growth decelerated during 1994-1998 and the country had excess capacity, the demand growth has accelerated considerably since then and 19 out of the 31 provinces are currently experiencing serious shortages of power supply which is affecting industrial production. Given its rate of GDP growth projections, and its relatively low level of present per capita annual electricity consumption (1,062 kWh), the forecast long term electricity consumption growth rate of 4.5% p.a. through 2020 may yet prove conservative.

6.20 ***Tariffs***: Tariffs differ from province to province and even within a province. Till recently a policy of "new price for new plant" was followed, resulting in a multiplicity of tariffs even within a province. Since 2000, China is moving on to unified tariffs based on average costs of generation, transmission and distribution. After the sector reforms of 2002, the generation tariff is expected to be on the basis of competition and retail tariffs would be a sum of competitive generation costs and regulated network tariffs. This is still in the process of evolution. Overall the level of average tariff at the level of SPC was around 4.5 cents/kWh in 2000. It is believed that tariffs had gone up notably since that time.

6.21 ***Sector Reform***: Since the end of 2002, the Chinese power sector has undergone structural changes. The State Power Corporation has been unbundled into five large generation companies and several transmission and distribution companies to introduce competition in the power sector. A State Electricity Regulatory commission has been set up to regulate network tariffs.

6.22 ***Export Possibility to Xingjian Province***: Xingjian Uyghur Autonomous Region has an area equal to one sixth of the total Chinese territory and has a population of 17.5 million growing at the rate of 1.28% per year. The interconnections among the eight regions of the Chinese power grid are not adequate to transfer fully the surplus of one region to another. Xingjian province is presently in the list of provinces with no special shortages or surplus of power.

6.23 Its installed generation capacity at the end of 2001 was 4,744 MW and its annual power generation is about 19.6 TWh. It experienced recently an annual electricity demand growth at the rate of about 8% compared to its annual GDP growth rate of 7.6%. Since 1993, it is reported to be receiving an annual supply of about 5GWh from the Kyrgyz Republic through a 10 kV line.

6.24 The well known Tarim Basin with significant oil[32] and gas reserves lies in this province. A gas pipeline going from this province all the way to the east with a length of 2,600 miles and an estimated cost of $5.2 billion had been committed and the work is ongoing. When finished in 2007, it is expected to carry 12 million cubic meters of natural gas every year to the eastern provinces. The region is also believed to have notable coal reserves too.

6.25 It is reasonable to assume that on account of the oil and gas related activity the electricity demand in the province would continue to grow at about 7 to 8% per year. In that context, the Kyrgyz Republic and Tajikistan could hope to capture a part of this demand for the export of their hydroelectric power.

6.26 In the context of electricity prices in China rising as a result of the tightening of coal supplies and increasing oil and gas costs and in the context of electricity shortages, capture of a part of the Xingjian electricity market by the CARs is a possibility. However, the major growth in demand, and current deficits will be in the population centers on the East coast of China where

[32] Potential oil reserve estimates vary from a low of a few billion barrels to 80 billion barrels.

transmission distances for supplies from Central Asia become an issue. The Xingjian province at the moment can meet its demand with supplies within the province.

C. Iran[33]

6.27 With a population of about 66 million (2003) and a per capita GDP of about $1,000, Iran is endowed with an abundance of energy resources. It is believed to have over 8.6% of the world's oil reserves and 15% of the world's gas reserves, besides substantial reserves of coal and about 42,000 MW of hydroelectric potential. Nonetheless, it is a potential market for exports of electricity from the Central Asian Power System on account of its summer electricity shortages as well as the isolated nature of the grid adjoining Turkmenistan.

6.28 ***Sector Structure***: The Ministry of Energy is responsible for the energy policy. The operational responsibilities have recently been vested with Tavanir, which appears to be a holding company responsible for generation and transmission with 27 generation subsidiaries, transmission and dispatch subsidiaries. In addition there are 16 Regional Power companies and 39 Distribution companies reporting to the Ministry. There are also 27 companies for support services, 18 subsidiaries for engineering and management consulting services, 6 subsidiaries for training and research, 8 subsidiaries for financing and 27 subsidiaries for contracting for construction etc. reporting either to Tavanir or to the Ministry.

6.29 ***Infrastructure***: The total installed power generation capacity in Iran in 2001 amounted to 34,222 MW, of which 1,998 MW was hydroelectric, and the rest was fossil fuel fired. The thermal plant capacity consisted of oil or gas fired steam turbines (14,402 MW), gas fired combined cycle plants (4,060 MW), open cycle gas turbines (7,038 MW) and diesel fueled generation sets (540 MW). It also included a capacity of 6,190 MW not owned by government electricity agencies. About 70% of the thermal capacity was gas fired. The peak demand of the system was 21,790 MW in 2001 and annual electricity generation amounted to 130,083 GWh of which only 5,077 GWh was from hydroelectric units. A nuclear power plant with a capacity of 1000 MW had been under construction at Bushehr for a long number of years with Russian assistance and was expected to be completed in the first half of 2004.

6.30 The power system consists of three major networks: (a) the Interconnected Network, which serves all of Iran except for remote eastern and southern areas, using 440-kV and 230-kV transmission lines; (b) the Khorassan Network, which serves the eastern Khorossan province; and (c) the Sistan and Baluchistan Network, which serves the remote southeastern provinces of Sistan and Baluchistan. The government goal is to join these three networks into one national grid. Currently, these three grids cover 43,000 villages and around 94% of Iranians are connected to the power grids. The transmission system consisted of 10,079 km of 400 kV lines, 20,444 km of 220 kV lines, 13,210 km of 132 kV lines and 30,264 km of 66kV lines. Iran also has power links to neighboring countries, including Azerbaijan, Turkmenistan (started August 2002), and Turkey.

---

[33] Most of the information in this section is taken from the Iran Energy Environment Review Report prepared for the Bank in 2003. An exchange rate of 8000 Rials to a dollar had been adopted.

6.31 ***System Loss***: The overall electricity system losses in 2001 amounted to 21.3% consisting of auxiliary consumption of generating units (4.7%), transmission losses (3.7%) and distribution losses (12.9%). The distribution losses include an undetermined share of non-technical losses.

6.32 ***Power Market***: There were over 16 million consumers in the country and the total sales of electricity to them amounted to 97,171 GWh in 2001. The residential consumers had a share of 33.8% of the total sales, followed by industrial consumers (31.4%), commercial consumers (18.9%), agricultural consumers (11.4%) and others (4.5%). The seasonal variations in the Iranian power system is characterized by high demands during June-October driven by air-conditioning loads and relatively lower demands during November-May. The demand is highest in August and lowest in April as can be seen from the following Figure 6.2.

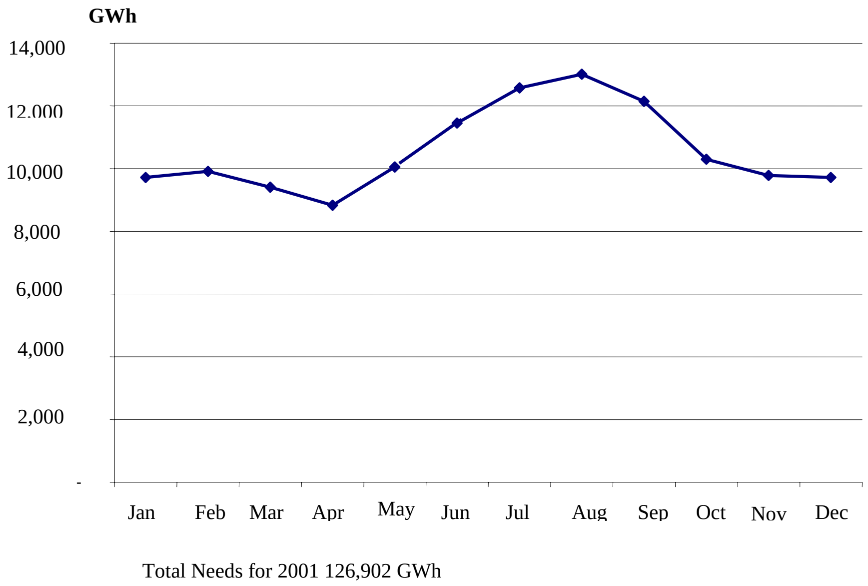


Figure 6. 2: Seasonal Load Curve in Iran in 2001

6.33 Recent estimates are that the annual shortage in the Iranian system is about 6 billion kWh and most of this shortage arises during summer.

6.34 ***Demand Outlook***: Electricity consumption during 1990-2000 grew at the average annual rate of 7.7%. A peak demand of 40,000 MW and an energy generation of 239 TWh are forecast for 2010. The installed capacity is planned to be tripled by 2020 to about 96,000. While the underlying demand projections appear somewhat optimistic and may need to be moderated on the basis of gradual reduction of price subsidies, the population growth and the scope for increases in specific consumption in the context of anticipated economic growth would prove to be a significant driver of the demand. The planned addition of 12,800 MW capacity during the Third Five Year Plan period (1999-2004) is reported to be lagging behind the target. The overall strategy is to add as much economic hydro generation capacity as possible and meet the remaining demand by gas fired combined cycle units and open cycle gas turbines. While fuel sources are available, financing for the new capacity is proving to be a major constraint. Invitations to private investors on a build, operate, and own (BOO) basis did not elicit much response. In November 2003 the first agreement for a 2000 MW open cycle gas turbine plant near Tehran on a build, operate and transfer (BOT) basis was signed.

6.35 ***Electricity Trade***: Electricity trade with adjoining systems would be used to even out seasonal capacity and energy shortages. It will also come in handy in the context of financing constraints to add new capacity. Iran exchanges power with Armenia and Azerbaijan and also exports power to Turkey. It may be seen from the following Figure 6.3 that its imports are rising during 1998-2001.

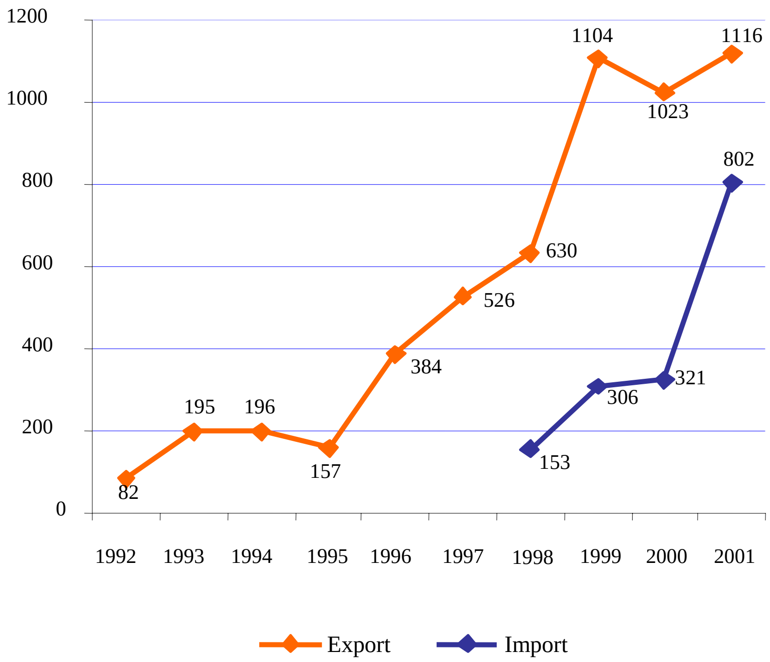


Figure 6. 3: Power Exports and Imports of Iran

6.36 Electricity from the Central Asian Power System could reach Iran in the Mashad area in the eastern province of Khorassan via Turkmenistan or via Afghanistan. Iran has entered into a 10-year power import contract with Tajikistan since mid-2002. Tajikistan's exports would be during the summer months, and the purchaser on the Iranian side is a corporate entity (as opposed to the national utility). The electricity transmission would occur via the existing lines from Tajikistan (Regar) through Uzbekistan (Guzar and Karakul) and Turkmenistan (Mari).

6.37 ***Electricity Prices***: Electricity prices in Iran lag behind supply costs. In 2000, the overall average electricity tariff was 88.5 Rials per kWh or 1.11 cents compared to an estimated supply cost of 195 Rials or 2.4 cents. The industrial tariff, at 121 Rials (1.51 cents) was subsidizing the residential tariff at 65.1 Rials (0.81 cents). Tariffs vary from province to province. The tariff prevailing in the Tehran area was as follows: Residential tariffs per kWh ranged from Rials 64 or 0.8 cents (for consumption below 300 kWh) to 559 Rials or 7.0 cents (for monthly consumption above 600 kWh). Industrial consumers paid a capacity cost of 108,000 Rials or $13.5 per kW per year and an energy cost of 102 Rials or 1.3 cents per kWh. Commercial consumers paid the same level of capacity cost, but an energy cost of 183 Rials or 2.3 Cents per kWh.

6.38 ***Marginal Electricity Costs in the Iranian System***: The least cost method of meeting incremental demand in the Iranian system is to add combined cycle gas turbines fuelled by natural gas. Based on a natural gas price of $ 1.5 /million BTU, and a capital cost of $700/kW for the combined cycle plant, the avoided cost/kWh at the generation level amounts to 3.56 cents.[34]

6.39 Iran appears to be considering electricity imports from Central Asia for several reasons. First, high rates of growth in electricity demand and the continued financing constraints to build the needed capacity in time to meet the demand is more than likely to result in the demand/supply gap widening if Iran remains solely dependant on indigenous supply. Second, the lack of a unified grid in the country will also hamper the ability to generate power where the necessary resources (e.g., gas and hydro) are available, and importing from neighbors (e.g., as is happening in the Mashad province) is often more economic. Third, entering into electricity trade relationships serves Iran's foreign policy agenda (as is happening in Armenia, Azerbaijan and Turkey) and would serve commercial interests as well – Iran has offered to help Tajikistan build the Sangtuda I hydro-power scheme, and given that Iran would have spare capacity (in the medium term) in the winter, can even export to its neighbors.

D. Pakistan

6.40 Pakistan has an area of nearly 800,000 square kilometers, a population of 148 million (35% of them living below poverty line) and a per capita GNP of $470 (2003). It has oil reserves of 310 million barrels, gas reserves of 750 BCM, coal reserves of 2.5 billion tons and 27,000 MW of hydroelectric potential. It has a large and extensive power sector with reasonable economies of scale. Despite its large generating capacity (19.5 GW) and consumer base (14.5 million consumers), nearly 40% of the population has no access to electricity. The annual per capita electricity consumption remains low at around 320 kWh.

6.41 ***Infrastructure***: Pakistan's installed power generation capacity at the end of 2003 was 19,478 MW of which 65% was thermal, 33% hydroelectric and 2.4% nuclear. The thermal plants were fueled mostly by oil and natural gas. A large hydropower project (Ghazi Barotha) with 1,450 MW was commissioned in 2002-2003. The electricity generated in the fiscal year 2002-2003 (the fiscal year ends on 30 June in Pakistan) amounted to 73,961 GWh.

6.42 ***Market***: The total number of consumers exceeded 14.5 million. Over 11 million of them were residential consumers. The share of the residential consumption in total sales was the largest at 46.7%, followed by industrial consumers (29.5%), agricultural consumers (10%), commercial consumers (5.8%) and others (8%). The system experienced some excess generation capacity during the last few years. Still power outages could not be avoided owing to transmission and distribution bottlenecks.

6.43 ***System Loss and Collection Efficiency***: Auxiliary consumption of generation units and transmission and distribution losses were estimated at around 30%. A significant part of this is

[34] The underlying assumptions for this computation are: (a) plant capacity of 300 MW; (b) Capital cost financed by 30% equity and 70% debt; (c) Return on equity of 15% and debt with a maturity of 20 years and an interest rate of 6% p.a; (d) Plant load factor of 70%; and (e) O&M Expenses of 1 c/kWh. The resulting per kWh avoided cost consists of: (a) 1.35 cents of fuel cost, (b) 1.21 cents of capacity cost, and (c) 1.0 cent of O&M cost.

attributed to power theft. Collection problems are also severe and the two major utilities have accounts receivables valued in excess of several months sales.

6.44 ***Sector Structure and Institutions***: The power wing of the Water and Power Development Authority (WAPDA) of Pakistan owns and operates 5009 MW of hydroelectric capacity and 5040 MW of thermal capacity. It also handles transmission and distribution in the entire country except the area around Karachi, which is handled by Karachi Electric supply Corporation (KESC). This corporation handles 1948 MW of thermal generation capacity as well as transmission and distribution in the Karachi area. Pakistan Atomic Energy Authority owns and operates two nuclear power plants with a total capacity of 462 MW. A large number of private independent power producers owned and operated 5,959 MW of thermal capacity and supplied power to WAPDA on the basis of government guaranteed and take or pay based power sales contracts. Distribution is organized in the form 8 Area Boards.

6.45 ***Sector Reform***: Since 1997 the government has set up an autonomous regulatory body, the National Electric Power Regulatory Authority, to regulate sector tariffs. WAPDA's power wing has been separated and corporatized as the Pakistan Electric Power Corporation. The hydro assets would continue to be in the public sector. It has been further unbundled into 3 generation companies, one transmission and load dispatch company and 8 distribution companies. The generation and distribution companies are to be privatized and competition is to be introduced in stages on the basis of regulated transmission access to all generators, distributors and perhaps the large industrial consumers. The 1,600 MW thermal power plant of WAPDA at Kot Addu was privatized to a strategic investor, who purchased 36% of the shares and secured management control. KESC is being privatized as a vertically integrated utility through the sale of government shares.

6.46 ***Tariffs***: The average retail electricity tariff in Pakistan in FY 2001-2002 was Rs 3.22/kWh or around 6 cents/kWh, compared to long run marginal cost estimates of about 7.3 to 7.4 cents/kWh. The price at which WAPDA buys power from IPPs, presently around 5.6 cents/kWh is a good proxy for marginal supply cost at the generation level.

6.47 ***Demand Outlook***: During the 10 year period FY 1992-93 to FY 2002-03, demand grew at an average annual rate of 3.7%. The growth level was relatively modest as a result of the economic downturn and periodic political unrests experienced during a good part of the period. For the period 2000-2010, forecasts based on moderate GDP growth rates and peaceful conditions seem to indicate an average annual electricity demand growth rate of about 6%. These forecasts further indicate that notable capacity and energy shortages would appear in 2005-06 and that capacity shortages could grow from 411 MW in that year to about 5,500 MW by 2009-2010.

Table 6.4: Pakistan Electricity and Peak Demand Projections						
	Year	Demand TWh	T&D Losses %	Auxiliary %	Generation TWh	Peak Demand MW
	2002	51	28.1%	4.0%	72	12334
	2003	54	25.3%	4.0%	77	13096
	2004	58	24.6%	4.0%	82	13895
	2005	63	23.9%	4.0%	87	14741
	2006	67	23.3%	4.0%	93	15640
	2007	72	22.6%	4.0%	99	16593
	2008	78	22.0%	4.0%	105	17604
Growth Rate during 2002-08		7.4%			6.4%	6.1%
	2009	83	21.1%	4.0%	111	18682
	2010	89	20.3%	4.0%	118	19826
	2011	96	19.5%	4.0%	125	21039
	2012	103	18.7%	4.0%	133	22327
	2013	110	18.0%	4.0%	141	23694
Growth Rate during 2008-13		7.2%			6.1%	6.1%
	2014	118	18.0%	4.0%	152	25446
	2015	127	18.0%	4.0%	163	27328
	2016	136	18.0%	4.0%	175	29349
	2017	146	18.0%	4.0%	188	31520
	2018	157	18.0%	4.0%	202	33851
Growth Rate during 2013-18		7.4%			7.4%	7.4%
	2019	168	18.0%	4.0%	216	35184
	2020	180	18.0%	4.0%	230	38679
	2021	192	18.0%	4.0%	246	41345
	2022	205	18.0%	4.0%	263	44195
	2023	220	18.0%	4.0%	281	47242
Growth Rate during 2018-23		6.9%			6.9%	6.9%

Source: Government of Pakistan – Pakistan Atomic Energy Commission

6.48 Longer terms forecasts to the year 2023 have also been prepared for the Private Power Implementation Board (PPIB) of the Government of Pakistan, the results of which are summarized in Table 6.4. These forecasts show that demand for Grid based electricity will grow from 51 TWh to 220 TWh, i.e., at an annual average rate of 7.2%; and peak demand will increase from 12,344 MW in 2002 to 47,242 MW, amounting to an annual average growth rate of 6.6%.

6.49 The policy makers in Pakistan are fully aware that the indigenous energy resource base is insufficient to meet such demand over the medium and long term. Accordingly, they recognize that imports of energy would have to increase, and they are considering import of electricity from the Central Asian republics via Afghanistan as an option to meet their demand. The Government of Pakistan has requested the Bank to play a lead role to help them to analyze such options (among others) as the regional electricity trade with Central Asia.

E. Russia

6.50 Russian power system, one of the largest in the world, adjoins the Central Asian Power System and represents a market with significant potential. The recently funded and ongoing construction of the second 500 kV north-south line in Kazakhstan would greatly enhance the power transfer capability between the Russian system and CAPS.

6.51 ***Infrastructure***: Russia is endowed with enormous energy resources such as oil reserves exceeding 60 billion barrels, gas reserves exceeding 47,000 BCM, coal reserves exceeding 157 billion tons and vast hydroelectric potential. Its installed power generating capacity at the end of 2002 was about 215 GW comprising 147 GW of thermal power plants fired by gas, oil or coal, 45 GW of hydroelectric capacity and 23 GW of nuclear power capacity. The total electricity generated in 2002 was about 890 TWh of which 584 TWh or about 65.5% was from thermal plants, 164 TWh or 18.5% was from hydroelectric units, and 142 TWh or 16% was from nuclear power plants. The power system had about 2.6 million km of high voltage and extra high voltage lines. Electricity demand, which declined from 1990 to 1998, resumed growth in 1999. The system is believed to have an excess capacity over demand of about 20% to 25%, but because of transmission bottlenecks in the vast system spread over several time zones, the actual system reserves tended to be around 10% to 15%.

6.52 ***Present Sector Structure***: The Russian government owns 52.6% of the shares of RAO UES. About 35% of the shares are held by foreign and domestic institutional investors and the rest by individual shareholders. RAO UES owns the national power grid and national load dispatch facilities, as well as most of the large thermal and hydro plants. It also owns varying percentages of shares (on average 49%) in the 72 Regional Power companies called Energos, which are vertically integrated power utilities serving the regions with their own generation, transmission and distribution facilities. Though the remaining shares in the 72 Energos are held by other institutional and individual investors, RAO UES (as the holder of the largest block of shares) has full management control over the Energos. RAO UES, its generation, transmission and load dispatch subsidiaries as well as the 72 Energos are collectively referred to as RAO UES Holding. This holding company has 72.5% of generation capacity and 96.1% of the transmission facilities and accounts for 70% of the electricity generation in Russia. Nine of the 11 nuclear plants are owned by Rosenergatom, a 100% state-owned nuclear power company and the two remaining units are directly owned by the Ministry of Nuclear Energy.

6.53 ***Market*:** RAO UES operates the wholesale electricity market called FOREM, in which the sellers are the large hydro and thermal power plants owned by RAO UES and others, the nuclear plants owned by Rosenergatom and the Ministry, as well as four regional Energos which have surplus electricity to sell. Eight other Energos use the FOREM for energy exchanges through sales and purchases. The other buyers in the FOREM are 59 regional Energos which have demands in excess of their own capacities and large industrial consumers. Regional Energos handle retail sales to end consumers within their region. In 2002, the volume of electricity passing through the wholesale market amounted to about 299 TWh or about 38% of the total electricity supply in the country of 790 TWh.

6.54 In the total retail sales (of 580 TWh) by the regional Energos, industries had a share of 48.9% followed by households, housing and communal services (22%), transport and telecommunications (11.5%), agriculture (3.4%), and others (14.2%).

6.55 ***Tariffs***: Generation tariffs for the power plants owned by RAO UES or by the state supplying to the FOREM, as well as the transmission tariff for the national grid are regulated by the Federal Tariff Service (FTS). Retail tariffs for end consumers in the regions are regulated by Regional Energy Commissions which are administratively controlled by regional governments, but are guided by the relevant federal laws and guidelines issued by the FTS.

6.56 Electricity tariffs in Russia vary from region to region and had been rising in the last few years at a rate faster than the rise in the prices of industrial goods. Nonetheless the level of tariff is not adequate to cover full supply costs and subsidies to households, agriculture and state financed organizations persist. The average tariff for households after taking into account the price discounts mandated to different privileged classes of consumers amounted in 2002 to 48.77 kopecks/kWh or 1.63 cents/kWh. The tariff for large industrial consumers averaged at 64.85 kopecks/kWh or 2.16 cents/kWh. The overall average tariff/kWh for the 13 major Energos ranged from 34.5 kopecks to 80.2 kopecks.

6.57 Information from Energy Regulators' Regional Association (ERRA) indicates that in Russia the electricity tariff per kWh at the producer level in the first quarter of 2003 was 1.45 cents. In the same quarter the clearing price in the wholesale market (FOREM) was 1.67 cents and the average end user price amounted to 2.78 cents. In terms of the Energy Strategy adopted by the government, the average end user price is expected to rise to 4.0 to 4.5 cents per kWh by 2020 corresponding to a generation level tariff of about 2.0 cents. Considering the marginal cost of generation in Russia estimated at 3.0, the question remains whether the projected end-user tariffs need to be increased more than envisaged.

6.58 ***Losses and Collection***: Collection problems in the Russian power sector have largely been overcome. Collections ran at around 102% of bills for current consumption implying that some of the arrears are also being collected. Most of the collections are in the form of cash and the problem of barter and offset payments has been largely eliminated. RAO UES is implementing a comprehensive and result oriented Cost Management Program in which reduction of network losses and theft of power and improved metering and billing figure prominently. 15% of the total cost saving in 2002 of RUR 14.5 billion ($483 million) is attributed to network loss reduction efforts.

6.59 ***Sector Reforms***: Russian power sector is in the process of being restructured to enable competition in the "generation" and "supply"[35] segments and continuation of regulation of network services. This process is expected to be implemented first in the "European" part of Russia, and with suitable time lags in the Siberian and Far East regions. This process would also involve the eventual disappearance of RAO UES, as the separate Federal Grid Company, Energos, and generation companies become independent companies as part of Russia's emerging competitive power market.

[35] Distribution function would be unbundled into network services and supply services. The latter will be driven by competition and the former will function on the basis of regulated prices.

6.60 ***Power Sector Outlook***: Till now the demand growth in Russia had been moderate and a situation of excess capacity prevailed. However many large units (including many nuclear units) are reaching retirement age and demand growth has resumed and is expected to grow at an average annual rate of 2.54% through 2020. The present tariffs do not leave adequate internally generated cash to finance the new investments in generation and transmission, which are expected to become necessary in the relatively near future. RAO UES is revaluing its assets in order to have a realistic depreciation expense component in the tariff. It also promoting the concept of tariffs being driven by investment needs. Based on these considerations the average sale price in the wholesale market could go up significantly in the next five to six years.

6.61 ***Electricity Trade***: Export of electricity is viewed as a priority by RAO UES as providing one of the sources of funds for investment. In 2002, RAO UES exported a total of 16.7 TWh of which 7.4 TWh went to former Soviet Union countries such as Azerbaijan, Belarus, Georgia, Kazakhstan, Moldova, and Ukraine. The remaining 9.3 TWh went to China, Latvia, Mongolia, Norway, Poland, Estonia, Turkey and Finland. The largest volume of export went to Finland (7.5 TWh). In terms of export receipts the first group of countries provided $117.46 million while the second group provided $175.30 million. The company aims to maximize its exports to west European destinations with higher electricity prices, and also get involved in retail sales in the importing markets to maximize export receipts. A recent forecast estimates that exports might grow to the level of 40 TWh by 2020. A new subsidiary “RAO UES Inter” had been formed to look after and manage exports. This company in turn sets up local subsidiaries in export markets to handle retail sales.

6.62 ***Strategies and Prospects***: Russia seeks the Nordic markets through Baltic ring arrangements (known as Baltrel) and markets in Turkey through Georgia, and markets in Moldova, Romania and the Balkans (constituting the so called second UCTE systems) through Ukraine. It also has long term interests in supplying profitable markets in China, South Korea and Japan making use of the large hydro resources in the Far East Russian regions. It also aspires to synchronize its grid with West European systems in the not too distant future. In pursuit of its aims RAO UES has been acquiring generation and distribution assets in Georgia, Ukraine, and Kazakhstan. RAO UES Inter is also eyeing the possibility of importing inexpensive hydropower from CAPS, partly to balance the regional systems like Omsk and partly to augment its pool of exportable surplus. Acquisition of the generation assets at Ekibastuz in Kazakhstan, offers to buy summer power from the Kyrgyz Republic and Tajikistan, and offers of help to construct Kambarata and Rogun hydro power projects may all be part of this strategy. Operation of CAPS in synchronism with the Russian system and the new 500 kV line in Kazakhstan should greatly enhance the export possibilities of power from CAPS to Russia. It will however be driven by the competitive nature of the cost of power from CAPS. If Russia succeeds in exporting its electricity to the UCTE countries at prices around 4.0 cents/kWh then it would provide a rationale for import of power from CAPS at prices higher than its own cost of generation. Russia’s recent ratification of the Kyoto Protocol may also be a reason for Russia to be looking at importing hydroelectricity from the CARs.

CHAPTER VII: INSTITUTIONAL ISSUES

7.01 Realization of the export potential of the CARs calls for tackling at least three groups of significant institutional issues. The first group of issues (the Water and Energy Nexus Issues) relate to the institutional arrangements necessary to operate the existing and proposed large multipurpose reservoirs and the associated hydropower facilities in a manner acceptable to all riparian states and for the optimal benefits of entire river basins. The second group of issues (Power System Operation Issues) relate to the need to reform and operate the power systems of the CARs to maximize electricity trade within CARs and with external electricity markets. The third group of issues (Investment Issues) relate to the organization and financing of the legal corporate entities to raise financial resources, construct, own and operate the new large hydro and thermal projects and market the electricity generated. Given the existing and anticipated dominant role for hydroelectric power in these systems, these three groups of issues are inseparably intertwined and call for a coherent resolution. Since a coherent resolution of these issues is indeed the objective of the proposed Water Energy Consortium under CACO, the last section discusses proposals for WEC's structure, roles and functions.

A. Water and Energy Nexus Related Issues

7.02 The large hydropower projects are to be built on international rivers and the construction of these projects would have significant and profound implications to the riparian states downstream. The need for securing agreements for water sharing and the regime of reservoir operation among all relevant riparian states is paramount, since without such agreements, security of the assets and projected revenues would be seriously compromised and it would not be possible to raise the resources needed for the investments.

7.03 Meaningful regional cooperation in the energy and water sectors is a major issue in the CARs. Under Soviet rule, they could operate multi-purpose reservoirs such as Toktogul in the irrigation mode for the benefit of irrigation in the downstream regions. The consequent electricity deficits in the upstream regions during winter were met by the synchronized *integrated* operation of the Central Asian Power System (CAPS) and by internal reallocation of fossil fuel supplies among the regions. Once CARs became independent states, these arrangements broke down and the subsequent efforts to restore some order encountered difficulties[36]. Solutions lie in operating the reservoirs for the maximum net benefit of the transboundary river basin, and would require a combination of updated agreements and key investments, as discussed in Chapter II (paragraphs 2.05 to 2.07).

B. Power System Operation Related Issues

7.04 During the Soviet era CAPS was optimized and operated as an integrated system. After independence, though the constituent power systems operate synchronously, they function more like inter-connected systems, rather than as integrated systems. The analyses in this Report has

[36] Discussions of these efforts, the difficulties encountered and proposed solutions have been dealt with extensively in the Water Energy Nexus in Central Asia Report of the World Bank.

shown that it would be necessary to engage in seasonal trade to make full use of the existing generation capacities; and that the proposed large thermal and hydro capacity additions can only be justified for trade with external electricity systems. Institutional reforms are necessary for facilitating such expanded trade in order to realize the export potential. The necessary and desirable elements of such reform are presented below.

- It would be necessary:

  - To ensure non-discriminatory third party access to the transmission system on the basis of transparently regulated and fair transmission tariffs.
  - To operate the transmission systems to meet both national and regional needs.
  - To form a regional association composed of the national transmission and dispatch operators (which are expected to remain in the public sector) underpinned by the necessary agreements, to achieve the above two steps. Such association would enable, without having to change ownership structures, the smooth regional operation[37] of the transmission grids; and identification of the needed reinforcements and new transmission links (to relieve congestion and enable smooth regional and extra regional trade). Europe's Union of Coordination of Transmission of Electricity (UCTE) provides a good model on which such an association can be based.

- While the above are necessary steps, it would also be desirable to:

  - Separate the transmission and load dispatch functions from the rest of the utility operations (such as generation and distribution) into independent corporate entity for transmission and dispatch, since these transmission system operators (TSOs) would support trade more naturally than vertically integrated utilities.
  - Implement the 1999 decision to create an integrated electricity market in the CARs and a power pool mechanism to facilitate the operation of the pool[38] and convert Energia into the Pool operator. This would eventually enable the creation of a competitive electricity market at the regional level[39].
  - Create competent and independent regulatory bodies in each country whose mandate would include ensuring that electricity is being sourced from the cheapest source in the region. In addition, these national regulatory bodies could form a Regional Council of Regulatory Bodies and this Regional Council could encourage agreement upon regional matters such as the regional grid code, transmission tariffs for trade etc.

Some of the desirable actions (separation of TSOs, separate regulatory bodies) have been realized in Kazakhstan and the Kyrgyz Republic.

---

[37] Transparency is the key need for smooth operation

[38] Initially, dispatch would follow mostly bilateral contracts and the pool would essentially be a balancing pool.

[39] This is the level at which competition would make sense, since some of the markets, for example the Kyrgyz Republic and Tajikistan, are (i) too small and (ii) have single dimension large assets to enable national level competitive electricity markets.

C. Investment and Related Institutional Issues

7.05 The investment needs being considered in all the countries for rehabilitation of existing plants and networks are summarized in Table 7.1. As can be seen, the size of the proposed investments are large - the realization of all the projects identified, including rehabilitation of transmission and distribution and new projects need about US$13 billion in real terms over the next 20 years.

Table 7. 1: Summary of the Central Asia Countries Investment Plans (in constant US$ million)

Investment Project	2004-2005	2006-2010	2011-2015	2016-2020	2021-2025	2004-2025
Kazakhstan						
Transmission and Distribution	324.0	972.1	0.0	0.0	0.0	1296.1
Generation - Ekibastuz GRES-1 Rehabilitation	0.0	308.0	132.0	0.0	0.0	440.0
Generation - Other Kazakh Large and Medium Units Rehabilitation	0.0	395.9	460.1	214.0	0.0	1070.0
New Generation Units	0.0	0.0	0.0	922.3	162.8	1085.0
Kazakhstan Total	324.0	1676.0	592.1	1136.3	162.8	3891.1
The Kyrgyz Republic						
Transmission and Distribution	50.0	200.0	0.0	0.0	0.0	250.0
Generation - Bishkek CHP 2	0.0	196.0	0.0	0.0	0.0	196.0
Generation - Kambarata 1 HPP	0.0	0.0	1067.0	873.0	0.0	1940.0
Generation Kambarata 2 HPP	0.0	140.0	140.0	0.0	0.0	280.0
The Kyrgyz Republic Total	50.0	536.0	1207.0	873.0	0.0	2666.0
Tajikistan						
Transmission and Distribution	25.0	285.0	0.0	0.0	0.0	310.0
Generation - Sangtuda I HPP	0.0	296.0	74.0	0.0	0.0	370.0
Generation - Rogun HPP, Phase I and II	0.0	0.0	1453.0	1002.0	0.0	2455.0
Tajikistan Total	25.0	581.0	1527.0	1002.0	0.0	3135.0
Uzbekistan						
Transmission and Distribution	172.9	691.8	288.2	0.0	0.0	1153.0
Generation - Talimardjan TPP	100.0	480.0	720.0	0.0	0.0	1300.0
Generation - Rehabilitation of the existing TPPs.	87.0	522.0	246.8	80.7	213.5	1150.0
Uzbekistan Total	359.9	1693.8	1255.0	80.7	213.5	3603.0
Total Central Asia	759.0	4486.8	4581.1	3091.9	376.3	13295.1

The prioritization of the investments needs for the countries should be:

- Focus on loss reduction first, followed by generation rehabilitation.
- Undertake, in parallel, electricity trade using existing surpluses both within and outside Central Asia. In this regard, Russia becoming a serious importer of hydro electricity from Kyrgyz and Tajikistan will require the completion of the North-South line in Kazakhstan.
- Then consider implementing the new projects, beginning with the smaller ones and those that do not need riparian agreement. This would include Talimardjan in Uzbekistan, Bishkek II in the Kyrgyz Republic, and Sangtuda I in Tajikistan. Uzbekistan is likely to complete Talimardjan I on its own, and the recent commitments of Iran (US$150 million) and Russia (US$50 million) towards

constructing Sangtuda I have significantly enhanced the chances of realization of this project.

D. Proposals for the Formation of a Water and Energy Consortium

7.06 The recent formation of the high-level CACO and its focus on regional cooperation in the water and energy sectors through the establishment of a Water and Energy Consortium (WEC) seems to be an auspicious start to enable the operation of existing reservoirs to derive optimal benefit for all riparian states, and facilitate the construction and operation new multipurpose reservoirs. Kazakhstan, which has been nominated by CACO to take the lead in the energy and water sectors, has set up a technical experts working group with representation from all member countries, and this working group has prepared a Protocol on the 'Conceptual Approaches to the Formation of a Water Energy Consortium' (Appendix 7.1). This Protocol envisages the organization of the WEC as a corporate entity. Further, all four member countries would have equal voting rights and decisions would be made only on the basis of full consensus. The main objectives of the WEC would be to: (a) ensure optimal operation of reservoirs in accordance with the Water Sharing and Reservoir Operation Agreements; (b) enable the mobilization of investments for rehabilitation of existing assets and for new construction of both water and hydropower facilities; and (c) create the conditions for coordination of hydro and thermal power generation and for expanding electricity export. It also envisages the establishment of regional task forces to develop these concepts further and to seek the help of international financial institutions to obtain advisory, technical and financial assistance for establishment of the WEC and for the preparation of feasibility reports for the new investment projects.

Criteria for Evolving the Institutional Structure of WEC

7.07 However considering the complexity of the tasks (with political, economic and commercial dimensions) to be handled by WEC a more nuanced and a specialized set of institutional arrangements would appear to be called for. While corporate entities would be appropriate for the commercial tasks of raising financial resources, rehabilitating the existing assets, constructing, owning and operating new assets, and domestic and export sales, other forms of organization have to be considered. The political economy dimension needs to be addressed by concluding Water Sharing Agreements and Reservoir Operation and Water Release Agreements among the riparian member states, and effective multilateral monitoring and enforcement of these agreements needs to be arranged. Institutions with equal voting rights and consensus based decisions would be appropriate for the latter set of tasks, while they would be impractical and ineffective for commercial tasks. Further, the envisaged arrangements should look at the possibility of avoiding the creation of 'yet another new' institution and make the best use of existing institutions by absorbing them where possible, or reshaping them to serve the desire objectives. The institutional political and economic framework needs to incorporate flexibility, such as allowing for changing basin priorities, incorporating public input, and applying new information and monitoring techniques and technologies. Examples of changing basin priorities would include recognition of secular increases in the level of annual water inflows in the basin and tailoring sustainable and reliable solutions to meet the power requirements of upstream countries in the region (especially during the winter) and addressing the environmental priorities (of Kazakhstan) that more and more of Syr Darya water should reach the Aral Sea. Finally the institutional framework should enable national structures to participate effectively in international/regional efforts and serve the regional objectives.

Existing Institutions and Their Limitations

7.08 In the water sector, the need for a mechanism for regional water resource management was recognized very early after independence and an Interstate Commission for Water Coordination (ICWC), was established through an agreement reached in February 1992. The main functions of ICWC, as defined in its founding charter, are to: (a) determine water management policy for the region, as well as the limits on water consumption annually in the Basin for each republic and for the region as a whole; (b) allocate available water resources for various purposes, including the need for water to reach the Aral Sea and schedule water reservoir operations accordingly; (c) determine the future program for water supply and measures to implement the program; and (d) coordinate construction of major works.

7.09 The ICWC comprises officials (generally Ministers or Deputy Ministers) from the Ministries of Water and Water Resources Agencies of all the member countries. ICWC's decision making is based on the proposals formulated and analyzed by its secretariat located in Khodjent. Allocation of water and monitoring water flows are the responsibilities of the basin water management organizations, called BVOs, one each for the Syr Darya and Amu Darya basins. Scientific and information support at the interstate level is provided by the Scientific Information Center (SIC) of the ICWC.

7.10 In the electricity sector, the Central Asian Power Council (CAPC), comprising representatives from the electricity or grid companies of the CARs, has been established and this Council formulates quarterly power exchange schedules. There are also a number of multilateral and trilateral agreements between the upstream states (the Kyrgyz Republic and Tajikistan) and downstream states (Kazakhstan and Uzbekistan), which regulate the water and energy flows and set out a framework for mutual obligations and benefits. The Unified Dispatch Center, Energia, in Tashkent is responsible for maintaining the balanced and synchronized operation of the power transmission and distribution system. Energia's Dispatch Service performs the task of translating the quarterly power exchange schedules into daily schedules for generation unit commitment. Energia's Energy Regime Service attempts to balance irrigation and hydropower requirements, which is the most controversial issue in the region. Energia also has the responsibility for ensuring overall system security and for frequency regulation.

7.11 ***Limitations.*** ICWC is purely a water-focused body with no representation from the energy or environment sectors; this narrow focus has proven to be a major handicap in a system in which water and energy interests are intertwined. The BVOs and the Energia lack an international character, consist almost exclusively of staff and officers of the host nation and do not give the impression of functioning impartially among the constituent member countries. Their expenses as well as the expenses of the Secretariat of ICWC are met by the host nation only. Neither ICWC nor the BVOs and Energia have any power or mechanism to enforce the implementation of the Agreements.

A Five-Tiered Structure for WEC

7.12 Under these circumstances it would perhaps be appropriate to consider a five- tiered institutional framework for the water and energy related issues. As shown in Figure 7.1, at the *apex*, there would be the Council of the Heads of State (of CACO) to provide the overall vision of regional cooperation, identify the specific areas of cooperation, the extent of such cooperation and lay down the basic governing principles. At the *second level* there would be the Council on Water and Energy Consortium consisting of Prime Ministers or Deputy Prime Ministers to decide on policy issues. At the *third level* there would be Supervisory Board for the WEC, comprising the Ministers of Water and Energy. At the *fourth level* would be the Executive Directorate of the WEC with departments for Water and Energy. At the *fifth level* there would be the corporate legal entities carrying out generation (including reservoir operation), transmission, and load dispatch. New hydro projects would be constructed and operated by similar corporate legal entities in accordance with the Agreements among the riparian states concerning water sharing and reservoir operation regimes.

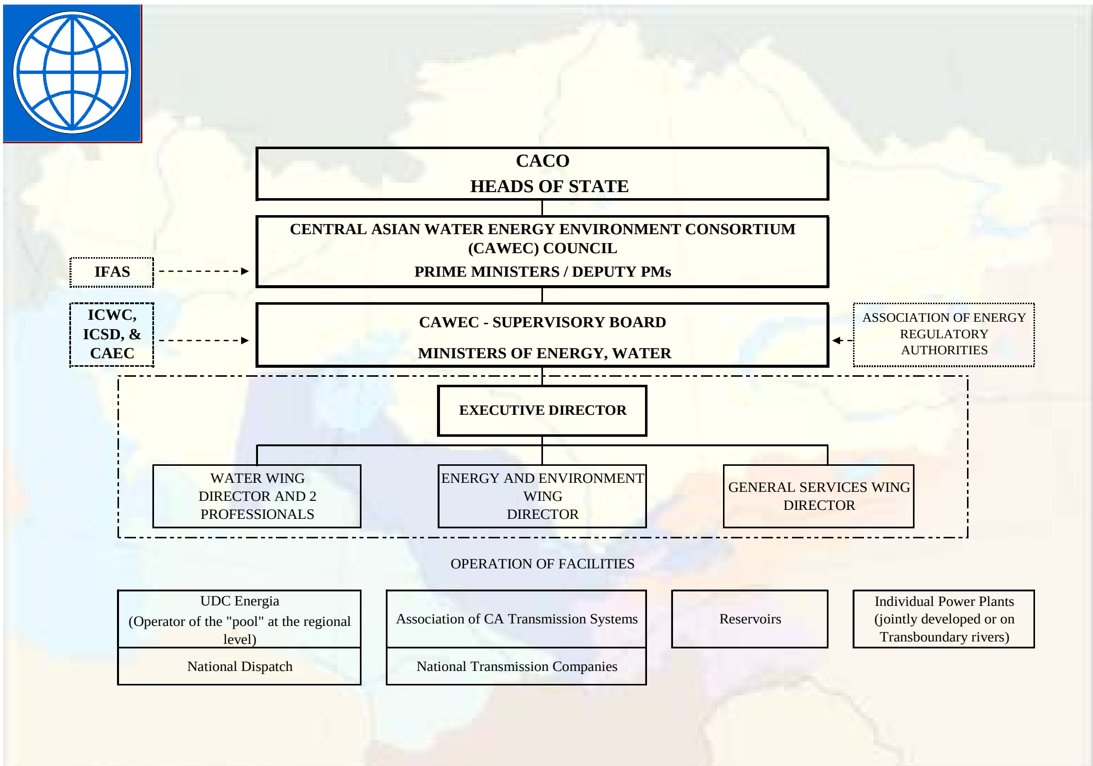


Figure 7. 1: Suggestions for an Institutional Framework for Water Energy Consortium

7.13 Somewhat on the lines on which G-8 functions, the Council of Heads of States would meet once a year. Prior to this meeting the WEC would have resolved most of the issues faced during the previous year and place before the Council only those issues that could not be resolved at the level of the WEC. The WEC is envisaged to meet once in six months, while the task forces of the Secretariat would meet as often as needed. There is no need to adopt a corporate structure at these three tiers. They could function as inter-governmental committees with equal representation for all member countries.

Relationship with Existing Organizations and Other Institutional Issues

7.14 Consideration should be given to subsume ICWC into the WEC in the long term. In the short term, given its extant nature and links to national water organizations, the proposal is to have an association agreement on cooperation between ICWC and the WEC. Similar association arrangements are appropriate for CAPC in the short term. The WEC Executive Directorate needs to be staffed by competent professionals drawn equitably from *all member countries* and supported by international experts to the extent needed. The expenses of the WEC and its Executive Directorate, have to be met jointly by all governments[40]. It may also be appropriate for these agencies to be governed by a special charter approved by the parliaments of all member countries.

Evolving a Legal Framework for WEC

7.15 A legal framework should be developed to underpin the work of the WEC and the associated bodies. For trans-boundary waters such as the Syr Darya and the Amu Darya, it is desired at the highest levels of the governments in the CARs that the sharing of trans-boundary waters should be done according to international law. It is useful to note that there is no 'international law' governing transboundary waters, but the following is available: (i) the convention of the Protection and Use of Transboundary Watercourses and International Lakes signed in Helsinki in 1992 (commonly known as the Helsinki Convention) and (ii) the UN Convention on the Law of the Non-Navigational Uses on International Watercourses (commonly known as the UN Convention). As such, these are not laws by themselves, but only provide principles based on which the appropriate legal framework for specific situations can be developed. Therefore, while ratification of these conventions is desirable, what is really needed is incorporation of the principles of these Conventions into a specific Agreement to govern the WEC and the related water use agreements etc. It would, therefore, be useful to develop an overall Framework Agreement appropriate to the circumstances of CARs. WEC could develop specific agreements for water release regimes and reservoir operations for the proposed new hydro projects and transmission access agreements under the overall Framework Agreement.

Institutional Aspects for Investments

7.16 The institutional structure most suitable for constructing and operating new generation and transmission projects is clearly that of a corporate entity. Each of the projects analyzed in this report are discussed from their institutional structure point of view.

- Large projects such as Rogun and Talimardjan II may need to be regional. The size of investments needed for them are beyond the financing capabilities of the countries themselves. Securing the large amounts of debt and equity financing needed from outside sources is contingent upon firm arrangements being in place to export the power

[40] Part of the expenses of institutions like BVOs and Energia could be met from user fees. However depending on funds from IFIs or Donors for this purpose is not considered sustainable or desirable.

to the power systems both within and outside the CAPS. Such large generation projects may therefore have to be conceived of as export oriented *regional projects* to be jointly owned by: (a) all the relevant riparian states (in the case of Rogun); (b) the importing countries; and, (c) where possible, private sector investors. Such joint ownership by several states would help the projects overcome the problems associated with level of external indebtedness and credit limits of individual countries such as Tajikistan. Joint ownership by riparian states would tend to minimize water related disputes and create greater understanding of, and confidence in, the adherence to the agreed operating regimes. It would also provide all states a measure of control over the reservoir operation. Joint ownership by the importing states could greatly improve their commitment to long-term imports, as has been demonstrated by other regional power projects in the developing world. Box 7.1 gives two examples of such projects in South America and Africa jointly developed by two or more riparian states. Another good example of inviting importers of power to be shareholders is provided by the Theun Hinboun Hydropower Project in Laos (see Appendix 7.2). It also highlights the efficacy of public private partnership and the useful role that an IFI (such as the ADB in the Laos case) can play in a project like this.

Box 7. 1: Two Examples of Jointly owned Hydropower Projects

The Itaipu Hydroelectric project on the Parana River, with an installed generation capacity of 12,600 MW is the world's largest hydroelectric project. It has been jointly developed by a joint stock company "Itaipu Binacional" owned by the Brazil and Paraguay and established under the Itaipu Treaty of 1973. The first unit was commissioned in 1983. In 2000 it generated 93.4 TWh of electricity and met 95% of the demand of Paraguay and 24% of the demand of Brazil. The agreement to develop the project needed to be reached among all three riparian countries, Brazil, Paraguay and Argentina. The company pays royalties to the governments of Brazil and Paraguay and sells the electricity to utilities in Brazil and Paraguay.

Manatali Hydroelectric Project on the Senegal River is a joint development by three countries – Mauritania, Mali and Senegal in West Africa. They have established a joint stock company proportionally owned by the three countries. This company has constructed the 200 MW facility and the related transmission lines.

- Kambarata I hydro project in the Kyrgyz Republic appears to be highly capital intensive and uneconomic; and proceeding with Kambarata II hydro projects without first constructing Kambarata I should be very carefully examined as it entails many risks. Nonetheless, if it were to be pursued on the basis of the new feasibility studies recently commissioned with help from RAO UES International of Russia, it may have to be jointly owned by the governments of the Kyrgyz Republic, Uzbekistan, Kazakhstan and likely importing states such as Russia. Since the operating regimes of Kambarata I and II have to be strictly coordinated with that of Toktogul, the joint owners of the new project would have some measure of oversight and control over the operation of all these facilities, including Toktogul reservoir, though it is expected that it would continue to be fully owned by the Kyrgyz government.

- Bishkek II thermal power project which appears to be the best option to meet the winter electricity shortages in the Kyrgyz Republic calls for an investment of the order of $200 million and could conceivably be implemented on the basis of a Public Private Partnership approach. Since Uzbekistan and Kazakhstan perceive the augmentation of winter electricity supply in the Kyrgyz Republic is the best insurance for the adherence by the Kyrgyz authorities to agreed water release regimes of Toktogul reservoir, they could conceivably be invited to make equity investments[41] in this project. This might induce them to provide uninterrupted fossil fuel supplies to the project.

- Sangtuda I hydropower project, prima facie, appears to be economic. Given the significant commitment made to develop this project by Russia (US$50 million) and Iran (US$150 million) it would likely be multi-country endeavor.

- The large thermal projects Talimardjan I in Uzbekistan and Ekibastuz Rehabilitation could be constructed and operated by the existing power companies which own them as the investments needed to complete them are modest.

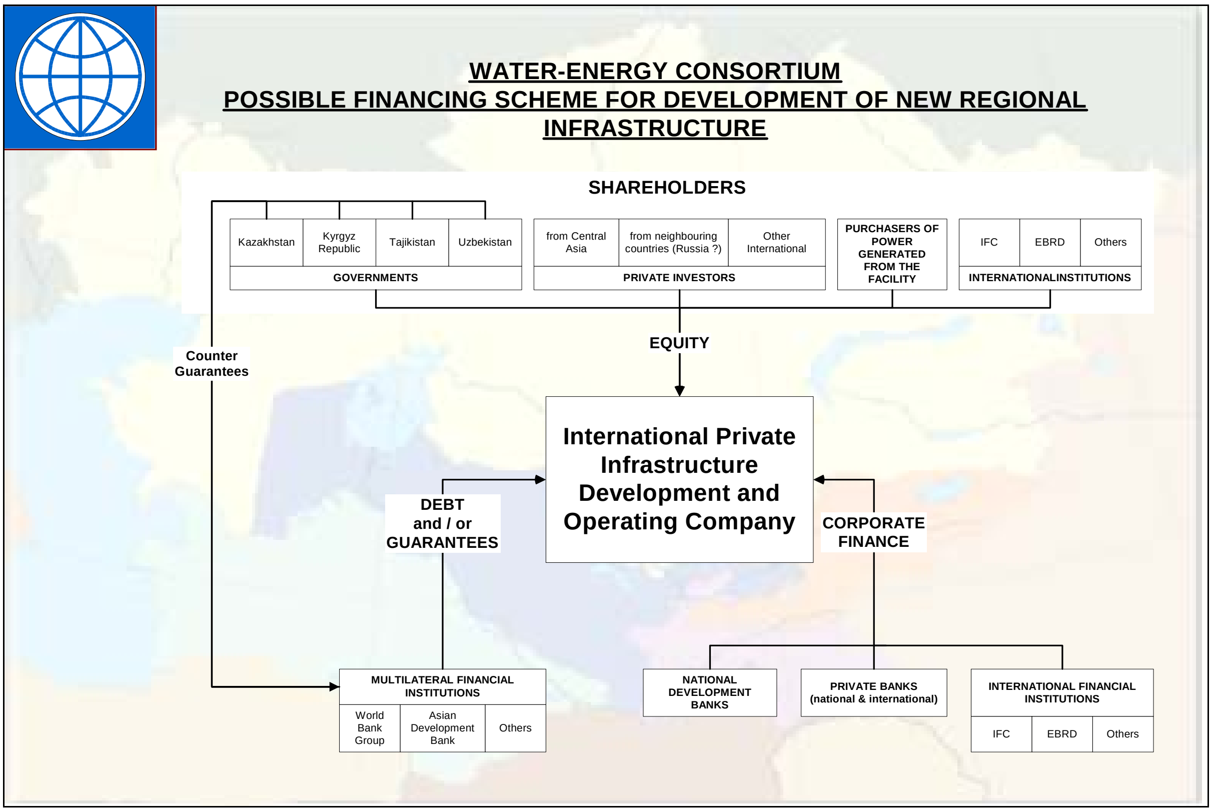


Figure 7. 2: Financial Scheme for Development of New Regional Infrastructure

7.17 Private sector participation is quite necessary to realize these projects, and to enable this a proper investment climate needs to be created and sustained through the adoption of sound policy, legal, and regulatory framework. Private investors, supported by financiers such as EBRD and IFC, could be mobilized to complement public funding for financing the electricity

[41] The equity could possibly come from the gas supply company of Uzbekistan and coal supply companies of Kazakhstan.

distribution in all four countries, and for electricity generation in Uzbekistan and Kazakhstan, which can happen through concessions and/or outright privatizations. For the large projects, however, assuming that the regional/multi-investor approach is adopted, an international corporate entity needs to be formed with equity participation by several states as well as the private investor. IFIs like EBRD and IFC could mobilize non-sovereign guaranteed finance along with private investors. IFIs like World Bank and ADB could provide long term debt to the international company against the joint guarantees to be provided by the member governments holding equity stakes in the company. A schematic representation of the above three-element institutional structure for attracting the financing for large projects is shown in Figure 7.2.

Transmission Investments

7.18 For transmission investments within the CARs, the state owned national corporate entities responsible for the transmission function would be the appropriate entities to undertake the construction of the new transmission projects to facilitate electricity exports. The equity financing needed for such transmission projects may have to be raised through internal generation of cash from the electricity sector through tariff adjustments and through efficiency improvements relating to loss reduction. The loans could then be raised from the world markets with the help of, and participation by, the IFIs and bilateral donors.

7.19 With respect to specific and radial transmission extension lines, dedicated to supply power to a export market such as the Almaty - Urumchi line or even the Surhan- Mashad line, an independent transmission project (ITP) approach, one in which equity participation by the exporting and importing states and by the private sector is possible, may be more appropriate. A good example of Public-Private participation in a transmission project is the Powerlinks Transmission Project in India (see Box 7.2).

Box 7. 2: Power links Transmission Project in India

Tata Power Company (a private power company) and the Power Grid Corporation of India (a state owned transmission company) have invested 51% and 49% of the equity of $79.5 million and have raised long term loans from IFC ($75 million), ADB ($66.3 million) and local banks and financing institutions ($44.2 million) to finance the construction of five 400 kV and one 220 kV lines of about 1200 km length and 3000 MW of power transfer capacity between Siliguri of West Bengal and Mandaula of Uttar Pradesh near Delhi at a total cost of $265 million. The project is on the basis of a BOOT contract to build, own and operate the project for 30 years and transfer it thereafter to the Power Grid Corporation. The lines are under construction and are expected to be completed by July 2006. The entire transmission capacity will be placed at the disposal of the Power Grid Corporation under a Transmission Service Agreement.

CHAPTER VIII: BENEFITS, RISKS AND THE WAY FORWARD

A. Benefits

8.01 The expected benefits are at least threefold. *First*, electricity trade within the region would enable the CARs to meet their demand at a lower cost than if they were to rely solely on their indigenous resources. For example, the Kyrgyz Republic plans to develop Kambarata I hydro scheme to meet its long term demand. However, this study demonstrates that electricity from Kambarata I would cost more than 7 cents/kWh, compared to the much less expensive electricity from Uzbekistan or Kazakhstan. *Second*, Kazakhstan and Uzbekistan would benefit from importing hydro electricity (from the existing hydroelectric stations) in summer from the Kyrgyz Republic and Tajikistan, as the economic costs of such hydroelectricity are lower than those of their own thermal power plants. By doing so, and by reducing fossil fuel based electricity generation on a seasonal basis, these countries can conserve their fossil fuel resources, and also might gain from carbon trading. *Third*, electricity exports beyond the region would indeed contribute significant economic benefits to the region as a whole. Not only the countries that generate and export electricity benefit, but also the transit countries e.g, Kazakhstan and Uzbekistan, would reap the benefits of transit income. Also, the building of large reservoirs like Rogun would help provide multi-year regulation of the Vaksh River, and therefore contribute to further developing irrigated agriculture, with its own attendant benefits.

B. Risks

8.02 The development of the energy sectors of the CARs, both individually and collectively, is as important to be realized as part of realizing the export potential. In this regard, the CARs face several major risks, many of which belong to the realm of political economy. These risks can be categorized as Reform Risks, which essentially affect the development of the national energy sectors; Cooperation Risks that affect the development of national as well as regional trade; and Market Risks, which affect the realization of export potential beyond the region. These risks are discussed below.

8.03 ***Reform Risks***. Although all countries have adopted some level of policy and institutional reforms of their energy sectors to transition to a market economy, the implementation of these reforms is very uneven. Kazakhstan has made most progress in reforming the industry structure, private sector participation, and pricing. Uzbekistan has become quite aggressive in pricing reforms, and has made progress in industry structure reform by creating a holding company structure with separate companies for generation, distribution and transmission. However, the Kyrgyz Republic and Tajikistan, where reforms are needed urgently, are lagging the most. Pricing reforms and private sector participation have become highly politicized in the Kyrgyz Republic in recent years, and the country is facing both Parliamentary and Presidential elections in 2005. In Tajikistan, a firm plan for reform of pricing, industry structure and private sector participation is yet to be adopted.

8.04 In addition, all countries need to put in place effective social protection schemes to accompany energy reforms. Equally important, the countries need to improve their investment climate to increase the chances of attracting private investments that are surely needed to realize the investments. Moreover, in view of the fact that trade at the margin would be needed to meet the demand at least cost, the countries should move away from the energy self-sufficiency policies.

8.05 Implementation of these reforms is within the control of the individual countries themselves, and are actually fundamental for national sectoral development as well as for electricity trade within Central Asia and with neighboring countries. Pricing reforms in the two hydro countries for example, would give them urgently needed resources for rehabilitating their power networks and reducing losses, which could lead to reduced demand and therefore have more surpluses for exports on a seasonal basis.

8.06 ***Cooperation Risks***. This set of risks affect development of the national energy sectors as well as the possibility of enhanced electricity and water trade within the region.

- **Water Energy Nexus Risk**. This problem, in the Syr Darya basin, still exists, despite attempts to resolve it since 1998, and despite the many possible solutions that have been put forward. Resolution of this problem would have significant impact on meeting domestic electricity demand in the Kyrgyz Republic, and would involve expanded energy trade on commercial terms. However, each of the countries involved have different solutions to the problem (see Chapter II, paragraph 2.03) and reconciling these and implementing a solution satisfactory to all will be a challenge in the current environment. A solution to this problem is seen as a litmus test for regional cooperation.

- **Riparian Risk**. This is an extension of the Water Energy Nexus Risk as far as the Syr Darya basin is concerned, and will affect the building of the Kambarata schemes. Uzbekistan and Kazakhstan are unlikely to agree to Kambarata since building this scheme would increase the Kyrgyz Republic's capability to regulate the Naryn river close to 100% (which means that the Kyrgyz Republic can in theory hold all the waters in Naryn in the Toktogul and Kambarata reservoirs), ***unless*** of course the downstream countries are given the operational rights to Toktogul. This, understandably, is not agreeable to the Kyrgyz Republic, thus diminishing the chances of Kambarata coming to fruition.

    - Building the Rogun scheme would face a similar riparian risk as both Uzbekistan and Turkmenistan are downstream riparians on the Amu Darya. Turkmenistan is not a member of CACO (for example) and its views regarding the building of Rogun are not known. The solution lies in developing Rogun as a regional project, with the involvement of the riparians, who would have a say in the operation of the reservoir, but all of this needs to be worked out.

- **Transmission Access Risk.** The integrated nature of the CAPS grid and the landlocked status of the CARs makes these countries dependent on each other for transmission of power to reach parts of their own market (e.g., Tajikistan is dependent on the Uzbek grid to transmit power from its generation sources in the south of the country to the more industrialized north) and export markets. In order to supply Russia, the Kyrgyz Republic needs the access to the Kazakh grid). Such interdependence creates risks of capacity –

Uzbekistan claims that there is no spare capacity in its part of the grid adjoining Tajikistan to transmit Tajik power (either for Tajik's own use or for export to Russia via the Kyrgyz Republic and Kazakhstan). This risk is manifest in Uzbekistan's reluctance so far to sign the Power Trade Relations Agreement with Tajikistan enabling power trade between the two countries, despite its having initialed the draft contract in the context of negotiating a loan of $120 million from ADB and EBRD for the construction of transmission lines and substations. Also this gives rise to hold up risks – Kazakhstan and Uzbekistan can indirectly dictate when and how much water can be released in the reservoirs in the Kyrgyz Republic and Tajikistan by refusing access to their electricity grids. When this is juxtaposed with the Kyrgyz Republic's tendency to ensure that every drop of water released from the Toktogul reservoir produces electricity (i.e., if it cannot use or sell electricity it would tend not to release water), the risk is all too real and serious.

Here too, the solutions lie in a combination of agreements and investments. Agreements are needed so that Kazakhstan and Uzbekistan give Third Party Access to their transmission grid; and by the Kyrgyz Republic and Tajikistan to observe optimally beneficial water release regimes. Investments are needed to complete the construction of the North South Line in Kazakhstan, which is needed to enable supply from the larger generation capacities to the CAPS in winter, and to enable exports to Russia in summer. Financing, in part by EBRD, for a section of this high priority line is in place, and the Kazakhstan government is planning to complete this line by 2008. Investments would also be needed to overcome the capacity problems that may exist in the southern part of CAPS (southern Uzbekistan, southern Kyrgyz Republic and Tajikistan), especially when Talimardjan I begins to dispatch. Recognizing this possibility and to create alternative transmission routes for their own power, the Kyrgyz Republic and Tajikistan are building a 54-km 220 kV transmission line between Kanibodom (in Tajikistan) and Batken (in the Kyrgyz Republic). It may be worthwhile to think of extending this line to link the Nurek cascade in Tajikistan and the Toktogul cascade in the Kyrgyz Republic, thus creating alternative transmission routing which would essentially link Kazakhstan (and therefore the Russian grid) via the Kyrgyz Republic with Tajikistan (and therefore Afghanistan) without going through Uzbekistan. Details of this scheme are discussed in Appendix 8.1.

- ***Resource Risk.*** Currently the supply of gas from Uzbekistan to the Kyrgyz Republic and to Tajikistan is not reliable for several reasons, the most important of which is the inability of the Kyrgyz/Tajik authorities to pay for the gas in cash and the need to rely on barter arrangements. In this context, the proposal that Bishkek II be based on Uzbek gas may be perceived from the Kyrgyz perspective as a gas supply risk. However, the Kyrgyz perspective may be driven by their efforts to try to promote the construction of the Kambarata schemes, which are seen as projects of national importance, and therefore adoption of Bishkek II to solve Kyrgyz's winter deficit problem (as opposed to Kambarata) is likely to be a politically tough decision.

Perceptions apart, in view of the fact that there has not been an independent evaluation of Uzbek gas reserves, the perception of this risk is likely to persist also for Talimardjan I and especially for Talimardjan II.

Solutions lie in the Uzbek authorities quickly conducting an independent evaluation of their reserves, and continuing to attract private/foreign investment in order to increase the reserves. In addition, the Bishkek II plant needs to be structured as a commercially viable entity privately owned and managed and capable of contracting for gas and paying for it in cash. The gas supply entity, Uzbekneftegaz in Uzbekistan, is commercializing rapidly and is slated for privatization; it naturally prefers to export to cash paying customers. There may be other approaches for fuel supplies for Bishkek II – it could be designed as a coal fired plant instead of gas, for example.

8.07 ***Market Risks.*** It is clear that the CARs do have the potential to provide electricity to markets outside the region. While Central Asian supplies should be cost competitive in these markets, the cost advantage is not overwhelming. Also, realization of electricity export potential is not just about economics. Electricity trade is politically more sensitive than general trade since electricity supply is often viewed as a national security issue. Also, trade of significant amounts of electricity requires long-term commitments and a clear perception, in the importing countries, that the supplier can be relied upon to fulfill its commitments. The level of trade that will justify the construction of major facilities to service the export markets and the associated commitment of capital will be predicated on the alleviation of supply security concerns on the part of the importing countries and an associated perception that the political climate and the business environment in the exporting countries are stable.

8.08 In addition to the above general risks that apply to long-term electricity trade, there are specific risks with each of the target markets. Afghanistan has potential demand but is constrained in its ability to pay for imports, and in any case is a small market in the immediate future for the larger new projects in the CARs. Access to the Pakistan market would involve transit and the associated construction of transmission facilities through Afghanistan and there would be questions of who will bear the responsibility for such transmission links, and also perceptions of security risks. The demand growth in China is centered on the population centers of the East Coast, a considerable distance from Central Asia. Access to the Russian market will require access to the North-South transmission line across Kazakhstan that is under construction and would be dependent on the interest and willingness to purchase power by RAO UES and later by whatever power companies that emerge from Russia's power sector restructuring. CARs would also face the risk that supplies to Iran from the Kyrgyz Republic and/or Tajikistan will likely have to compete with supplies from Turkmenistan and will have to transit Afghanistan or Turkmenistan as well as Uzbekistan.

C. The Way Forward

8.09 Addressing the risks and impediments to realize the full regional trading and export potential will require time and strong political will both within the CARs and in the target markets. While the international financial community is prepared to work with and support all the countries, such support cannot replace the political will needed to make the necessary compromises for regional cooperation. The World Bank, in concert with other development partners is providing advice and technical assistance (including this report) to aid the formation of the Water-Energy Consortium, to help put in place the requisite legal, institutional, and financial framework.

8.10 The Central Asian suppliers of electricity should approach the issue of expanded export activities with the recognition that a significant expansion in export levels will take some time to develop, and they should, therefore, focus on the objective of building towards this longer term goal in a phased fashion. A possible scenario for development of Central Asia's electricity generation and trading activity is shown schematically in Figure 8.1 below. This contemplates the phased introduction of measures to make capacity available beginning with the introduction of loss reduction programs to be followed by construction of new capacity needed to meet winter demand within the region (Talimardjan I and Bishkek II) and the completion of the transmission link to Russia through Kazakhstan. These activities should be completed in a medium term time frame (up to 10 years). These phases have a relatively high probability of going ahead.

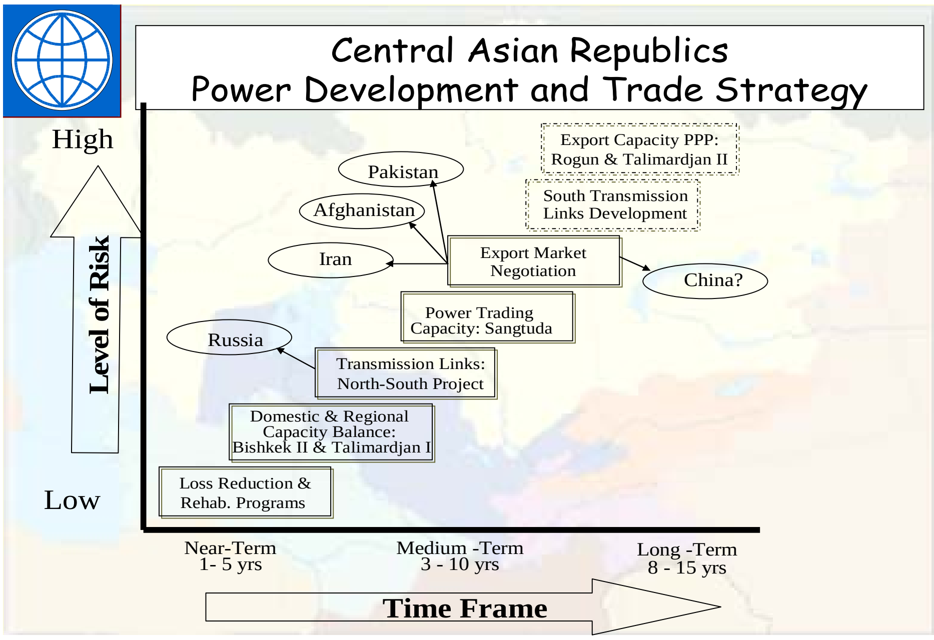


Figure 8. 1

8.11 Integral to this process, the CARs will need to address the risks discussed earlier. The policy reforms will need to be accelerated in parallel with the loss reduction programs – in fact the two are intertwined closely that one would not happen without the other. Bishkek II and Talimardjan I will contribute to the solution of the Cooperation Risks, which would require overcoming the political resistance to adopting Bishkek II (instead of Kambarata); and ensuring the necessary agreements on water releases and transmission access are in place.

8.12 The chances of realizing updated agreements to govern electricity trading between countries within the region would be higher if these were attempted on a bilateral basis in the initial phase, as is being done with the Batken Kanibodom line between the Kyrgyz Republic and Tajikistan, and between the Kyrgyz Republic and Kazakhstan on Kyrgyz exports to Russia. If these arrangements are all based on a consistent set of principles they will facilitate increased intra-regional trade, and will reinforce the multilateral agreements that is now being explored (with little success to date).

8.13 As regards trade with the markets outside the immediate Central Asia region, it appears likely that such trade will initially be limited to seasonally based activity at the margin. The more extensive level of trade that would justify the construction of major facilities would be ‘demand driven’ by the importing countries. Accordingly, the outlook for implementation of new projects focused on the export markets, e.g., Rogun and Talimardjan II that could occur in a subsequent phase is too uncertain at this time to justify the commitment of significant resources to these large generation projects. What is needed to realize these projects is the alleviation of supply security concerns on the part of the importing countries, the existence of transmission infrastructure to access the markets and a politically stable environment.

8.14 The one exception is the Sangtuda I hydro project in Tajikistan, where both Iran and Russia are making financial commitments to help develop this project. Russia’s role in the development of the large projects of the CARs needs to be better understood. At the moment, it is playing multiple roles – as an importer of Central Asian electricity, as an investor, and as a strategic partner in construction and metals (aluminum) industry. It also became a member of CACO in 2004. Russia’s expanding role in the CIS energy sectors in general and Central Asia in particular may be due to the following reasons:

- Energy supply security - its own gas reserves and electricity generation capacities are declining and Russia may be aiming to shore up its now growing demand for energy, with (still) cheap electricity from CIS, especially Central Asia.
- With ratification of the Kyoto Protocol in early 2005, incentives will exist to shut down highly polluting coal capacity;
- Russia needs to fulfill its energy supply obligations to Western Europe. At present these are limited to gas but in future may include electricity; and
- While western investors currently view the new generation projects as high risk ventures, RAO UES of Russia, believes that it can mitigate many of the risks and has expressed particular interest in some of the proposed hydropower projects.

RAO UES, in combination with Iran (and perhaps Kazakhstan) represents the best opportunity for the Sangtuda I project to be implemented in the medium term.

Next Steps

8.15 Further analytical and technical assistance work is needed to continue to build consensus for the power sector development and trade strategy identified in this report. Future phases of this work should focus on: (a) helping to prepare more detailed demand projections (using an end-user approach) and help prepare Least Cost Investment Programs for each of the CARs; (b) undertaking a transmission system assessment including the load flows on a projected basis to understand the bottlenecks, investment needs and costs of service; (c) through country visits to the target markets, confirming the willingness and modus operandi of importing Central Asian electricity in the short, medium and long term; (d) developing commercially oriented contractual documents (e.g., power purchase agreements and transmission service agreements) for intra-Central Asian trade and for extra-Central Asian trade; (e) developing viable PPP financing structures for chosen projects; and (f) developing institutional options for this regional approach to energy development.