Hydropower Investment Promotion Project (HIPP)

REGIONAL ELECTRICITY MARKET OVERSIGHT

Wednesday, 31 July, 2013

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USAID/CAUCASUS OFFICE OF ENERGY AND ENVIRONMENT

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Acronym	Term
MOE	Ministry of Energy of Georgia
MIE	Ministry of Industry and Energy of Azerbaijan
MINENERGO	Ministry of Energy of Russia
GSE	Georgian State Electrosystem
TEIAS	Turkish Electricity Transmission Company
ESCO	Electricity System Commercial Operator
HPP	Hydro Power Plant
NPP	Nuclear Power Plant
TPP	Thermal Power Plant
PSRC	Public Services Regulatory Commission of the Republic of Armenia
GNERC	Georgian National Energy and Water Supply Regulatory Commission
IAEA	International Atomic Energy Agency
R2E2	Renewable Resources and Energy Efficiency Fund

1 INDIVIDUAL MARKET ANALYSIS

This section of the report will provide an overview of the electricity markets of individual countries in Caucasus region and Turkey. The section will review historical, current and projected generation and consumption, as well as countries' interconnections with their neighbors.

The following five countries will be examined: Armenia, Azerbaijan, Georgia, Turkey and Russia.

1.1 ARMENIA

DEMAND FOR ELECTRICITY

Electricity demand in Armenia has increased by an annual avarege of 3.3% from 2008. For the year 2012 total consumption of the country was 5.12 TWh. During 2012 industry consumed approximately - 23% of total electricity of Armenia, the residential sector - 37%, transportation – 2% and the commercial and public sector - 38%. Peak demand has also showas an increaing trend from 2008.

Table 1.1 Peak Domestic Demand and Energy (without/with losses) of Armenia; Historical data

	Peak MW	Energy GWh
2008	1204	4729.7 / 5493
2009	1062	4378.8 / 5090
2010	1053	4507.7 / 5213
2011	1251	4869.7 / 5637
2012	1322	5119.5 / 5923

Sources: PSRC (www.rsrc.am), Settlement Center

GENERATION RESOURSES

Armenia's electricity system has over 3,390 MW of installed capacity. Currently only 66 percent is operational (2,550 MW). 53 percent of the total installed capacity is thermal, 34 percent is hydro and 12 percent is nuclear. Armenia also has a small wind power plant with 2.6 MW installed capacity.[1]

Electricity production in 2012 was 8 TWh, 29% of which was provided by Nuclear, 29% by hydro and 42% by thermal. It is seen that the consumption is satisfied by thermal generation too that relies entirely on imported energy.

The shares of thermal and hydropower plants in the capacity and generation have increased in recent years as several new plants have been built.

Table 1.2 Generation Resources of Armenia, 2012

Generation Resources	Capacity [MW]	Annual Generation [MWh]
Hydro	1 052	2351.3
Thermal	1 931	3374
Nuclear	408	2311
Wind	2.6	
Other Renewables		
TOTAL	3 394	8036.3

[1] Public Services Regulatory Commission of the Republic of Armenia (www.psrc.am)

Source: PSRC

Typically in Armenia nuclear power plant provides base load capacity, thermal power plants operate to meet peak demand during winter period but can also be run as base load plants when the nuclear power plant goes offline for maintenance; hydropower plants provide daily load variations, but have lack of operable capacity during winter months.

More than 50% of thermal power generation units in Armenia are old and they need a refurbishment. Thermal power plants were built in 1970s and are in poor operating conditions. The nuclear power plant is one of a few remaining nuclear power reactors in the world that was built without primary containment structures. It is regarded by international nuclear regulatory agencies as inherently unsafe and is scheduled to decommission in 2021. At present time existing NPP life extension for 10 years is considered.

EXISTING TRANSMISSION INTERCONNECTION

Armenia has high voltage interconnections with all its neighbors. However, the lines going to Turkey and Azerbaijan are currently not in operation for political reasons. There are no future plans for energy trade between the two countries.
Existing transmission network of Armenia is as follows:

Table 1.3 Armenia Interconnection

Country	Type of Connection	Maximum Capacity (MW)	Current Status
Azerbaijan	One line 330 kV (107 km)	420	out of use
	One line 220 kV		
	Two lines 110 kV		
Georgia	One line 220 kV (65 km)	250	operational
	Two lines 110 kV		
Turkey	One line 220 kV (65 km)	300	out of use
Iran	Two lines 220 kV (78.5 km)	400	operational

FUTURE GENERATING FACILITIES

Armenia's energy strategy emphasizes development of indigenous resources and priority should be given to renewable energy production. Thus, county is planning to diversify its electricity generation by using renewable resources. There exists significant renewable energy potential. It is estimated that Armenia has more than 1,000 MW of technically viable capacity from solar photovoltaic (PV), 300-500 MW from wind, 250-350 MW from unexploited small HPPs, and 25 MW from geothermal. There is also potential for producing roughly 100,000 tons per year of biofuel from local plants.[2]

According to the Armenian RE Roadmap project, the contribution of the renewables in Armenia can be increased by 2020. In 2012 RE production generated 310 GWh, and it is forecasted to generate 740 GWh in 2015 and 1500 GWh in 2020.

[2] *Armenia Renewable Resources and Energy Efficiency Fund (R2E2)*

The government of Armenia is planning to build a new nuclear power plant with 1000 MW of installed capacity. It will become operational in 2021 and will be a replacement of Metzamor NPP, which is scheduled for decommissioning between 2017 and 2021. Armenia thus needs significant new investments in order to maintain necessary generation capacity gap. Now this project isn't realistic and doesn't include in Government program for 2013-2017. The table below presents the summary of main investment projects in Armenia.

Table 1.4Investment Projects in Armenia

Technology Type	Installed Capacity (MW)	Annual Generation (million kWh)	Expected Implementation Date
Small HPPS (<10 MW)	260	600	2025
Medium Size HPPs	275 - 300	1300 - 1400	2015
Wind farms	200	525	2025
TOTAL	735 -760	2425 - 2525	

Source: Armenian Energy Sector Overview, Energy Strategy Center.

FUTURE CONSUMPTION

The demand for electricity is expected to increase in the coming years. Ministry of energy of Armenia with the help of USAID in 2010 made forecast estimation, The growth rate is 2.7% between 2010 and 2020, on average.

Under these conditions, in 2015, the peak load is estimated to be about 1350 MW and 1540MW in 2020.
Estimated energy and peak demands for the planning period are given in the table below.

Table 1.5 Estimated Peak Domestic Demand and Energy(without plants self-consumption and with losses)

	Peak (MW)	Energy (GWh)	Change (%)
2015	1350	6150	2.70%
2020	1540	7000	-2.70%

Source: Tecnnical Reort. Phase 1.USAID funded project "Assistance to energy sector to strengthen energy security and regional integration", TetraTech, 2010, www.armesri.am

Taking into account last year situation (Table 1.1.) we can estimate the peak load as no more 1450MW in 2015 and 1650MW in 2020.

1.2 AZERBAIJAN

DEMAND FOR ELECTRICITY

Consumption of electricity in Azerbaijan was increasing during 1997–2006. In 2007 the increasing trend reversed and started to decline until 2010. The main reasons for the fall were tariff increase in January 2007, implementation of government's policy to install meters and increased bill collection. A further factor was the gasification program, which allowed the switching from electricity to natural gas for heating. In 2011, electricity consumption showed increased trend again (by 8 %) and reached 13.4 TWh.[3]

According to Azerenerji the demand for electricity is expected to double between 2012 and 2022, and to increase by almost 140% by 2025. The peak demand is also expected to double by 2022–2023.

Table 1.6 Peak Demand and Energy of Azerbaijan; Historical data

	Peak MW	Energy GWh	Annual Change (%)
2008	-	15,650	-22%
2009	-	12,393	-21%
2010	-	12,326	-1%
2011	-	13,369	8%

Source: MIE, 2012

GENERATION RESOURSES

Electricity generation in Azerbaijan is entirely based on natural gas, heavy oil (during peak demand) and hydropower. The country is using its natural gas resources increasingly for generation. After 2009 the share of oil products in electricity generation was entirely replaced by natural gas.

According to the 2013 statistics of Azerenerji, at present, 13 thermal and 8 hydro power plants are in operation. Total installed generation capacity is 6 315 MW, of which thermal power stations contribute 5,253 MW (83%) and hydropower stations make up most of the balance.

Electricity generation of the country increases annually an average of 4% from 1997. In 2011 total generation was 20.294 TWh. The share of thermal in total generation was 87% and share of hydro production - 13 %.

Table 1.7 Generation Resources

Generation Resources	Installed Capacity [MW]	Annual Generation [GWh]
Hydro	1,063	2,676
Thermal	5,253	17,618
Nuclear	-	-
Wind	-	-
Other Renewables	-	-
TOTAL	6,316	20,294

Source: Azerenerji; MIE

EXISTING TRANSMISSION INTERCONNECTION

Azerbaijan currently has the following interconnections with its neighbors:

Table 1.8 Azerbaijan Interconnection

[3] Source: Ministry of Industry and Energy of Azerbaijan

Country	Type of Connection	Maximum Capacity (MW)	Current Status of Line
Armenia	One line 330 kV	420	out of use
	One line 220 kV		
	Two lines 110 kV		
Georgia	One line 500 kV	850	operational
	One line 330 kV	250	operational
Russia	One 330 kV	500	operational
Iran	Two lines 154 kV (to Nakhichevan)		operational
	Two lines 132 kV		operational
Turkey	One line 150 kV	100	operational
	Two lines 220 -230 kV via Iran	40	operational

Source: ECON Study for the Caucasus Region, 2009

Although interconnection lines between Azerbaijan and Armenia do exist, no power exchange takes place. It is related to the political dispute from 1989. There are no plans for resumption of energy trade between the two countries.

FUTURE CONSUMPTION

The government of Azerbaijan made a demand and peak load forecast estimation in 2007. The demand on electricity is expected to double between 2012 and 2022, and to increase by almost 140% by 2025. The peak demand is also expected to double by 2022–2023. Forecasted peak load and electricity consumption are shown on the following table.

Table 1.9 Estimated Peak Demand and Energy of Azerbaijan

	Peak (GW)	Energy (TWh)	Change (%)
2015	4.7	24	5.5%
2020	6.3	32	4.7%
2025	8.2	39	4.7%

Source: Energy Charter, Energy Efficiency of Azerbaijan 2013.

FUTURE GENERATING FACILITIES

Azerbaijan has large resources of almost all types of renewables: hydro, solar, wind, geothermal and biomass. There are significant agricultural operations in the country that could provide residues for biomass combustion or gasification. There also exists solar and wind energy potential due to favorable climatic conditions. The country is also rich with geothermal power.

The development of small HPPs is one of the main components in the RES sector. Although the country currently does not utilize all of its RES, the development of RES is also one of the government’s strategic priorities.

By the end of 2015, the value of total generating units will increase by 30 percent as according to Azerenerji three new thermal projects and 25 small hydro power plants are being constructed with the total 1815 MW of installed capacity.

1.3 GEORGIA

DEMAND FOR ELECTRICITY

The demand for electricity in Georgia has increased by an average 4 % per annum since 2007 including a 10 % rise between 2010 and 2011[4] on the background of double increase of GDP (in compare to 2007)[5].
For the year 2012 total consumption of the country was 9.4 TWh (increased by 1%). The greatest demand for electricity is during winter months as big share of the consumed power (up to 30%[6]) falls on the residential sector which use electricity for heating in winter months.

Table 1.10 Peak Demand and Energy of Georgia; Historical data

	Peak MW	Energy GWh
2008		8074.8
2009		7642.1
2010		8441.1
2011		9256.6
2012		9379.4

Source: Georgian State Electrosystem (GSE); ESCO

GENERATION RESOURSES

Total installed generation capacity in Georgia is over 3,300 MW. Approximately 80% of installed capacity is provided by renewables (hydro-generation).
The table below shows distribution of country's generating resources.

Table 1.11 Generation Resources of Georgia

Generation Resources	Capacity [MW]	Annual Generation [MWh]
Hydro	2,624	7,221
Thermal	693	2,477
Nuclear	-	-
Wind	-	-
Other Renewables	-	-
TOTAL	3,317	9,698

Source: ESCO, Electricity balance of Georgia 2012

In 2012 the gross electricity generation in Georgia was 9.7 TWh.The share of hydro in total generation was 74% and share of thermal production - accordingly 24 %. The market shares of the three largest generators made: Enguri HPP Ltd. – 33%; Mtkvari Energetika Ltd. – 12%; Vardnili HPP Cascade Ltd. – 6%.

Currently, Thermal Power Producers (TTPs) generate electricity from September to April, counting for 20 % of the total installed capacity of the system. Georgian generation displays seasonality effect and in particular the run-of-river hydros. The amount of hydro generated energy available is determined by rain or snow fall in each plant's hydrological basin. The problem with run-of-river is that with no, or only small, dams or reservoir to store water, the power plants rely on seasonal availability of water. This leads to diversion of excess water during summer and almost no

[4] ESCO, Energy Balances of Georgia
[5] National Statistics Office of Georgia
[6] Source: GNERC

power generation during drought conditions. This results in Georgia having to import energy during the winter period.

EXISTING TRANSMISSION INTERCONNECTION

Georgia currently has the following interconnections with its neighbors:

Table 1.12 Georgia Interconnection

Country	Type of Connection	Maximum Capacity (MW)	Current Status of Line
Armenia	220 kV	180 MW	operational
	110 kV	30 MW	from 2013
	110 kV	20 MW	from 2013
Azerbaijan	500 kV	850 MW	from 2013
	330 kV	250 MW	operational
	220/110 kV	230 MW	operational
Russia	500 kV	850 MW	operational
	220 kV	100 MW	operational
	110 kV	30 MW	operational
	110 kV	30 MW	from 2013
Turkey	400 kV	700 MW	from 2013
	220 kV	120 MW	operational

Source: Georgian State Electrosystem

FUTURE GENERATING FACILITIES

One of the main directions of the energy policy of Georgia is to increase the share of renewables in total generated power and satisfy the demand for energy by the own resources of the country.

The state program Renewable Energy 2008 is being implemented. It offers investors the list of HPPs to be built in various regions of Georgia (By the end of 2020, the value of hydro generating units will increase by 7 percent as 40 new projects are being constructed (39 HPPs and one wind farm with 50 MW of design capacity) with the 1879 MW of installed capacity and projected annual generation of 7410 GWh[7].

FUTURE CONSUMPTION

Note: There is no official projection for electricity demand in Georgia.

FUTURE TRANSMISSION FACILITIES

According to Georgian State Electrosystem, the country plans to build new transmission interconnections with its neighbors. The table below shows future projects of transmission facilities on the Georgia-Turkey and Georgia-Armenia borders.

[7]Source: Ministry of Energy of Georgia

Table 1.13 Perspective Transmission Projects of Georgia

Country	Type of Connection (kV)	Maximum Capacity (MW)
Turkey	200/154 kV(Batumi- Muratli)	350 MW
	400 kV(Akhaltsikhe -Tortum)	1050 MW
Armenia	500/400 kV (Marneruli-Alaverdi- Hrazdan)	

Source: Georgian State Electrosystem (GSE)

1.4 RUSSIA

DEMAND FOR ELECTRICITY

According to the data from ministry of energy of Russia (Minenergo) electricity consumption in 2012 as a whole amounted to 1 038.1 TWh which is 1.7% more than in 2011, but it is still below the 2000-08 average of 2.2%. The peak demand of 2012 amounted to 158,986 MW. According to an analysis framework of events "Energy of the Russian Federation", the number was recorded as a maximum load of Russia.

Table 1.14 Energy of Russia; Historical data

	Peak MW	Energy TWh	Annual Change (%)
2009	-	964.4	-4.6%
2010	-	1009.2	4.3%
2011	-	1021	1.2%
2012	158,986	1038.1	1.7%

Source: Minenergo

EXISTING GENERATION

In 2012, the total installed capacity in Russia increased by 6,134 MW (2.2%) and reached 223.1 GW. 68.1% of the installed capacity was thermal power plants, 20.6% was hydro power plants and nuclear power plants contributed the remaining 11.3%. The share of renewable energy (geothermal and wind) accounted only about 1% of the total installed capacity[8].

Electricity production in 2012 was 1053.9 TWh which is 1.3% more than in 2011. 177.1 TWh (17%) came from nuclear power, 708.8 TWh from thermal (67%) and 168 TWh (16%) from hydro[9].

Table 1.15 Generation Resources of Russia, 2012

Generation Resources	Capacity [MW]	Annual Generation [TWh]
Hydro	46	168
Thermal	151.9	708.8
Nuclear	25.2	177.1
Wind	-	-
Other Renewables	2	
TOTAL	223.1	1053.9

Source: Minenergo

[8]Press release on: "Power sector construction in Russia 2013. Development forecasts for 2013-2015." June 2013.
[9]minenergo.gov.ru

Russia's electricity supply faces a number of constraints: 50 GW of generating plant (that is more than a quarter) came to the end of its design life, and Gazprom cut back on the very high level of natural gas supplies for electricity generation. Gas-fired plants that now use about 60% of the gas marketed are scheduled to be halved by 2020.

EXISTING TRANSMISSION INTERCONNECTION

Electrical interconnections connect Russia with its neighboring countries. Characteristics of these connections are presented in table below.

Table 1.16 Russia Interconnection

Country	Type of Connection	Maximum Capacity (MW)	Current Status of Line
Azerbaijan	330 kV	500 MW	operational
Georgia	500 kV	850 MW	operational
	220 kV	100 MW	operational
	110 kV	30 MW	operational
	110 kV	30 MW	from 2013

FUTURE CONSUMPTION

Energy Strategy of Russia for the period up to 2030 adopted by the Russian Government in November 2009 projected that demand on electricity will grow in coming years. Annual power consumption growth rate was put at 4.5%. Demand on electricity is expected to reach 1,288 TWh in 2020 and 1,553 TWh in 2030 from 1,038 TWh in 2012.

The document also implies an increased need for import in the short run to meet domestic demand in Russia. The document emphasizes Ukraine and Kazakhstan as potential suppliers of electricity.

Table 1.17 projected Energy demand of Russia

	Peak MW	Energy TWh
2020	-	1288
2030	-	1553

Source: Energy Strategy of Russia for the period up to 2030

FUTURE GENERATION

In February 2010 the government approved the federal target program that envisages an increase of generation capacity at 355-445 GW in 2030. It requires construction of new power plants 78 GW of installed capacity by 2020 and total 173 GW - by 2030, including 43.4 GW nuclear. The plan also envisages decommissioning 67.7GW of capacity by 2030, including 16.5 GW of nuclear plant (about 7% of present capacity).

In July 2012 the Energy Ministry of Russia published a draft plan to commission 83 GW of new capacity by 2020, including 10 GW nuclear to total 30.5 GW producing 238 TWh. A year later Minenergo reduced the projection to 28.26 GW in 2019.

In parallel with this Russia is planning to increase hydro capacity by 60% to 2020 and double it by 2030.The aim is to have almost half of Russia's electricity from nuclear and hydro by 2030.

1.5 TURKEY

DEMAND FOR ELECTRICITY

Historically, energy consumption in Turkey has increased in proportion with the economic growth of the country. The demand on electricity has increased by an average of 8% per annum since 1960. It has been seen a 7-percent increase between 2001 and 2010, with much of the growth occurring between 2002 and 2008. Although demand fell in 2009 compared with the previous year because of the economic slowdown, in 2010 consumption increased by about 10 percent compared with the previous year. In 2011 total electricity consumption of the country was 229.3 TWh.

EXISTING GENERATION

Turkey has nearly doubled its installed power generating capacity in the last decade reaching a total of 57,000 MW at the end of 2012. The highest share of the installed capacity in Turkey is thermal plants. As of 2012, 38% of total installed capacity is natural gas, 16% lignite, 2% fuel oil, 7% imported and hard coal, ca. 4% of installed capacity is wind, geothermal and other renewables; Share of hydro capacity is 33%.

In 2011 the electricity production in Turkey was approximately 228.4 TWh. 171TWh (74.8%) was based on thermal plants and the remainder 58 TWh (25.2%) was produced by renewable sources such as hydro, geothermal and wind.

An analysis of power generation reveals the increasing importance of natural gas. In 2011, 44.7%, 28.3%, and 22.8% of total production was based on natural gas, coal and hydro respectively while the shares of oil derivatives and wind were 1.7% and 2.1%[10].

EXISTING TRANSMISSION INTERCONNECTION

Turkey has the following high-voltage transmission interconnections:

Table 1.18Turkey Interconnections:

Country	Type of Connection	Maximum Capacity (MW)	Current Status
Armenia	One line 220 kV (78.5 km)	300	out of use
Azerbaijan	One line 154 kV (87.3 + km)	100	operational
	One line 34.5 kV (44.5 km)	40	operational
Georgia	One line 220 kV (28 km)	300	operational
	One 500 kV		
Bulgaria	One line 380 kV (136 km)	500	operational
Iran	One line 154 kV (73 km)	100	
Iraq	One line 380 kV (16+ km)	500	out of use
Syria	One line 66 kV (7.5+ km)	40	operational

[10] TEIAS, 2012

FUTURE CONSUMPTION

According to TEIAS projections, the electricity demand will reach 398 or 434 TWh by 2020 depending on the high or low scenarios. The capacity to meet the peak demand should be at least 61-67 GW in order to meet such a huge growth in demand (TEIAS, 2012). Taking into consideration the required capacity additions and the maintenance-expansion requirements in grid infrastructure as well as the privatization process reveal the fact that potential investors face a free and competitive market with tremendous investment opportunities.

Section 2. Competition to new Georgian run-of-river HPP projects

According to the Government of Georgia's 2008 Resolution on Renewable Energy (RE 2008), new Georgian run-of-river projects are not afforded a feed-in tariff by the Government of Georgia. Rather, in theory, new HPPs are to sell their electricity output into the competitive Georgian electricity market for three months of every winter season (for ten years after commercial operation) and into the competitive regional electricity market for the rest of year and for all seasons after 10 years. In practice though, ESCO provides a feed-in tariff formula based on the average cost of generation from thermal power plants for at least three months of the winter season and sometimes many more months. ESCO's offer to provide a feed-in tariff blurs in reality what is the competition to new Georgian run-of-river projects.

Gas-fired Combined Cycles.

Georgia - Guaranteed Capacity (or Reserve Capacity as it is normally named).ESCO purchases capacity and energy from 3 power generating units at Gardabani power plant. ESCO pays the power plants for their capacity related costs and allocates these costs to the electricity sector entities. A sole source offer from the Turkish firm, Calik, proposes to construct a 230 MW (net) natural gas-fired combined cycle at the Gardabani power plant. The offer also suggests that a 25 year power purchase agreement be signed between Calik and ESCO.

In a competitive power market, there is no need for guaranteed capacity. The generation developers build capacity and produce electricity to meet the needs of the various markets including the hourly electricity balancing market and operating reserves market. If the TSO anticipates that there will be a shortage of capacity in the near future, then a tendering process for new generating capacity is completed and the cost allocated according to specific rules. That mechanism has yet to be developed in Georgia creation confusion of whether the country will continue to develop thermal power plants or rely upon the market to determine how best to meet the energy and capacity needs of the country.

Certainly the new gas-fired generation (55-60% efficiency) at Gardabani, most likely having a take or pay natural gas contract, will provide electricity to the market in Georgia and Turkey, somewhere in the 5.5-6.5 cents/kwh range assuming the existing price of natural gas and a 70% annual plant factor.

Azerbaijan. Azerenerji operates on gas-fired combined cycle and plans to build additional combined cycles in the future. The price of natural gas in Azerbaijan is based on policies set by the Government of Azerbaijan. Gas prices for domestic electricity production are kept quite low. It is uncertain what natural gas price the government will set for electricity production for export. Due to the priority for new

Georgian renewable power plants on the new transmission line to Turkey, electricity sales from new Georgian run-of-river HPPs will be protected from natural gas pricing policies in Azerbaijan.

Turkey. There are many existing gas-fired combined cycle plants operating in Turkey and many more are planned. These new plants are fired with natural gas coming mostly from Russiaat a price of approximately $450/1000c^{3}m. These plants set the market price for a majority of the hours during the year, therefore setting the benchmark for establishing contract prices for sales into Turkey from new Georgian HPPs. As long as the gas prices are stable or growing, these natural gas plants do not create a threat to Georgian HPPs, but a depression of gas prices, such as from a wide expansion of shale gas production, could have a material impact on the competitiveness of new Georgian run-of-river projects.

Large Reservoir HPPs.

Georgia. The Government of Georgia has aspirations for the construction of new large reservoirs by private investors in Georgian. Khudoni (702 MW) and Namakhavani (450 MW)are two examples of large reservoir HPP plants planned for development before 2020. The cost of construction for NamaKhavani in the feasibility study funded by NUROL was in the range of $1.2 -$1.4 billion while the cost of Khudoni was estimated in a feasibility study funded by the World Bank to be approximately $1 billion. Not only will these projects put downward pressure on the market marginal price, they will also take up capacity allocation on the international interconnections, especially to Turkey.

Turkey. The GoT is building large reservoir projects on the Chorok River near the Georgian border. These include Borchka HPP (300 MW), Deriner (670 MW), Yusufeli (540 MW) and Artin (332 MW).

Azerbaijan. Azerenerji is constructing the 420 MW Tovuz HPP. Though the electricity production from the new HPP will stay in Azerbaijan, it will free up thermal power (fired by low-priced natural gas) will compete against new Georgian HPPs.

New Nuclear Power Plant.

Armenia. For several years the Government of Armenia has promoted the idea of replacing Metsamor NPP with a new Russian-designed 1000 MW NPP. The plant's capacity would exceed the country's system demand for most of the year and its ability to cycle its operation would be quite limited. In other words, the new NPP would be built for domestic and regional electricity sales. The hourly amount of electricity sales in the off-peak periods, especially in the summer, could reach 800 MW from such a new NPP plant in Armenia. In the last five year energy strategy, 2013-2017, the Government of Armenia has removed all reference to a new NPP. It is not clear if consideration of the new NPP is now dead.

Turkey. The Government of Turkey has promoted the idea of construction of a large NPP station in Turkey. The Akkuyu Nuclear Power Plant is a planned nuclear plant at Akkuyu, in Büyükeceli, Mersin Province, Turkey. It would be the country's first nuclear power plant.In May 2010, the governments of Russia and Turkey signed an agreement that a subsidiary of Rosatom — Akkuyu NGS ElektrikUretim Corporation would build, own, and operate a power plant at Akkuyu comprising four 1,200 MW VVER units. The agreement was ratified by the Turkish Parliament in July

2010.Engineering and survey work started at the site in March 2011.The construction of the first unit will begin in 2014, with the four units put into service in 2019–22.49% stake will be sold to other investors.

Turkish Electricity Trade and Contract Corporation (TETAS) has guaranteed the purchase of 70% power generated from the first two units and 30% from the third and fourth units over a 15-year power purchase agreement. Electricity will be purchased at a price of 12.35 US cents per kW·h and the remaining power will be sold in the open market by the producer.In February 2013, Russian nuclear construction company Atomstroyexport (ASE) and Turkish construction company Ozdogu signed the site preparation contract for the proposed power plant. The contract includes excavation work at the site.

Source:NucNet, 22 February 2013.

New Coal-fired Power Plants.

Georgia.GIEC, a Georgian energy development and operating company, operates a small coal-fired power plant near its coal mines in central Georgia. The company is planning the construction and operation of two new 150 MW coal-fired power plants, one near their mine and one at the Gardabani power station. GIEC through its subsidiary, Saqnakhshiri, operates the Dzidziguri and Mendeli mines, located within the Tkibuli-Shaori coal basin. The company owns coal reservesof 331 million tons in the Tkibuli-Shaori region.

Turkey. Several new coal-fired plants, many of them along the Black Sea, are planned to be constructed in Turkey, some using local brown coal, some using imported hard coal. In either case, the production of electricity from new coal-fired power plants will be quite competitive with new run-of-river HPPs. There are several reasons, though, that the new coal-fired power plants are delayed and perhaps may even be canceled including: 1) meeting EU emission standards for large combustion plants, 2) local residents insisting on using local coal for creation of new jobs, and 3) international financial institutions, such as the IFC, deciding to distance themselves from with carbon-producing energy production.

Wind and Solar Power Projects.

Georgia. There are several potential projects in Georgia and the region for solar and wind farms. In fact small amounts of electricity are generated from these projects. The costs of wind power generation are between US¢ 9-11/kwh and solar powered production is between US¢ 12-15/kwh. Given the abundance of potential HPP projects with much lower cost of production, wind power and solar power projects will not most likely be built in large amounts for the planning horizon. That said, the price of wind and solar have dropped dramatically over the last 10 years and further drop in new facility costs could eventually make them competitive with new HPPs. With their low plant factor, 20-25%, and quite variable output makes them hard to compete in the competitive power market. Adding batteries to allow for better dispatch will only make their production costs higher.

Turkey. The Strategic Plan of Ministry of Energy and Natural Resources supports renewable energy targets for 2023, for example, 20 GW of new wind projects. These targets are supported with feed-in tariffs paid by the distribution companies. Solar and wind will therefore not compete in the competitive power market, but rather they will have the negative impacts for new Georgian run-of-river projects by lowering the competitive market prices (their production will lower gas electricity production at the margin) and perhaps creating congestion in the transmission network. Such large amounts of wind power will require significant additional thermal capacity and spinning reserve requirements to cover the variability of the production from the wind projects.

2.0 Regional Trading Opportunities

2.1.1 Georgia-Armenia electricity trade main options

Currently the Georgian power system is synchronized with Russia and Armenia operates synchronously with Iran.

Taking into account that power systems of Russia and Iran can't be synchronized, technically there are two possible connections of power systems of Georgia and Armenia:

- synchronously, when Georgia is disconnected from Russia or Armenia from Iran;
- asynchronously via a B2B (to be built).

Obviously, the first option is cheaper, meaning transmission costs.

2.1.2 Georgian and Armenian power systems synchronous operation

In the study[11] performed by TetraTech (USAID project "ASSISTANCE TO ENERGY SECTOR TO STRENGTHEN ENERGY SECURITY AND REGIONAL INTEGRATION"), the options of synchronous operation of Armenian and Georgian power systems (excluding Iran) for 2015 and 2020 were developed. The options include the new generation plans with renewable energy sources, the influence of the Russian gas price for Armenia on border, Armenian electricity import capacity to replace the production on TPPs as well as export from Armenia to Georgia for own use and re-export to Turkey.

All calculations were carried out by hours using GTMax software.

Economic volumes of electricity trade were relatively small (450 - 850 GWh per year), which in most cases allows to use an existing 220kV Alaverdi-Gardabani line. The only exception is the case with the construction of a new NPP with 1,000 MW capacityin Armenia, which is today can be considered unrealistic for the period under review.

Economic efficiency of such integration has been evaluated for Armenia on the basis of a comparison of options of integration with Georgia and the Armenian power systemisolated operation. The generation price for domestic consumers was accepted as efficiency criterion.

Generation costs for domestic consumers decrease depending on the price of gas for the considered power exchange and development of power generation capacity is given in the table below

[11]ECONOMIC EFFICIENCY OF THE ARMENIAN POWER SYSTEM INTEGRATION AND ANALYSIS OF IMPACTS OF NEW RENEWABLE DEVELOPMENT IN ARMENIA, 2012, Yerevan

Generation costs for domestic consumers decrease in million $	
2015	
Gas price $180/tcm	11.4 – 21.2
Gas price $240/tcm	8.7 – 20.9
2020 withexistingNPP	
Gas price $180/tcm	11.3 – 19.4
Gas price $240/tcm	18.0 – 27.9
2020 withexistingNPP decommissioning	
Gas price $180/tcm	6.9 – 8.4
Gas price $240/tcm	16.8 – 24.5

As can be seen from this table the optimal electricity exchange with Georgia allows to receive significant benefit for Armenia even as prices of Russian gas at the border are increased.

At May 2013 Russia raised the price of gas for Armenia to $ 270/tcm.In this regard appropriate calculations results require the adjustments, however, integration efficiency is about at the same level.

Unfortunately in Georgia wasn't established GTMax model and calculations were carried out with the generalized representation of the Georgian power system.

However, it was assumed that the electricity exchange can be carried out only when it is beneficial for both sides of the trade.As a result, export prices (with differentiation by seasons and hours)from Georgia to Armenia were taken higher than the potential to Turkey, and the import price from Armenia to Georgia, such that they were required either domestically or on the Turkish market (re-export). Detailsareinthereport[1].

There is a reasonable question.What caused efficiency of integration?

The main reason is that in isolated mode Armenia is obliged to unload the existing NPP practically during 9 months (essential in summer), which generation price is about $ 25/MWh only.This is due to the fact that usually in the power systems the generation of single unit can't exceed 60% of the system load (special automaticimplementation in Armenia allowed to raise this percentage to 75), but considering that the night load in summer is reduced to 380-400MW, and sometimes less, it's obvious that NPP must be unloaded.

The second reason is the necessity to run Yerevan TPP to pass the peak load in summer (in Armenia in summer the ratio maximum to minimum is very high - more than 2), which at night should work at least on a technical minimum (start-stop for a few hours is not practiced). This leads to a further NPP's unloading, since it works with a constant capacity.

The integration allows to avoid that and usethe cheap electricity.

First, integration is allowed to avoid the limitation of single unit capacity and second it is possible due to NPP's additional loading and a small import to stop the Yerevan TPP.Additional loading of NPP allows to offer lower (competitive) prices for Armenian export.

Armenian NPP decommissioning opens greater opportunities for Georgian export.

CONCLUSIONS

Georgian and Armenian power systems integration will bring economic benefits to both sides.

The special study must be performed for economic flows between Georgia and Armenia determination in details taking into account current situation in both countries.

2.1.3 Georgia – Armenia asynchronous operation

With today's situation, when Georgia is synchronized with Russia and Armenia with Iran, only the asynchronous operation between Armenian and Georgian power systems cab be realized.It is due to the inability to synchronize power systems of Russia and Iran in the foreseeable future.

For asynchronous operation the B2B construction is needed. In 2012 Fichtner carried out pre-feasibility study of this issue, which considered various options for B2B and substationat voltages 400/500kV 1050MW (costs up € 360M) and the 220 kV (250MW, costs € 72M) as the first stage of the projectwith subsequent extension.

Obviously, to invest in such expensive projects it’s needed to understand the issue of ROI, which is mainly determined by the volumes of flows through this link.

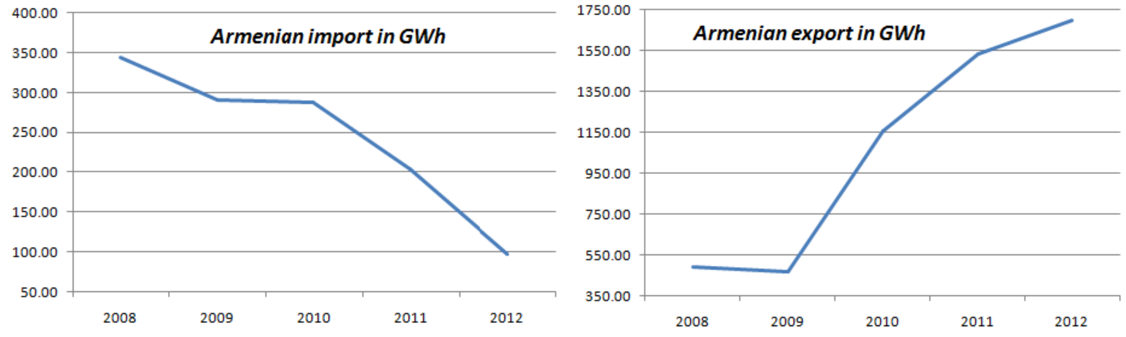
Currently Armenia has two contracts with Iran:

- electricity exchange;
- electricity exchange on Iranian gas (3MWh is exchanged on 1000cm)

The first type of contract involves the electricity exchange by seasons taking into account that the peak load in Armenia is in the winter, while in Iran - in the summer.

It should be noted that the volumes on this type of contract are reduced from year to year, which can be seen from the Armenian import historical data (see Figure below).

At the same time, the export volumes have sharply increased, which means the second type of contractpreferential use.



The benefit of this type of contract for Armenia lies in the fact that the new units built in Armenia allow to generate more electricity burning 1000cm gas than it must be deliver to Iran due to efficiency of these units (Yerevan TPP – 49%, unit #5 of Hrazdan TPP – up to 42%).In other words, the Yerevan TPP can generate up 25% on "free of charge gas" and unit #5 about 10%. Using old 200MW units of the Hrazdan TPP is inefficient in terms of this contract (low efficiency).

Under the conditions of Russian gas price raising it is clear that 100% of electricity generation on Iranian gas on the above two units is fully beneficial for Armenia. To ensure this the import from Georgia can be used that can grow each year (see Table below).

	Measurement unit	2013	2017	2022
Armenian domestic consumption	TWh	**5.9**	**6.5**	**7.4**
Net generation in Armenia, ingluding	TWh	**8.9**	**9.0**	**9.1**
NPP	TWh	2.5	2.5	2.5
TPPs	TWh	4.2	4.2	4.2
HPPs	TWh	2.2	2.3	2.4
Armenian surplus	TWh	**3.0**	**2.5**	**1.7**
Conditions determination for Armenian TPPs functioning on “free of charge” gas				
Gas requirement for Armenian TPPs fully operation on Iranian gas	bcm	1.050	1.050	1.050
Gas received by contract, incl. losses (3%)	bcm	0.970	0.808	0.550
Required export to Iran (for Armenian TPPs fully operation on Iranian gas), incl. losses (3%)	TWh	**3.25**	**3.25**	**3.25**
Estimated required import from Georgia	TWh	**0.25**	**0.75**	**1.55**

Contract "electricity in exchange for gas" is valid until 2027 and implies phased increase of supply (see Table below).At the moment there is a big difference between the contractual volumes and the actual deliveries from Armenia, which determines the potential export from Georgia to Armenia which can re-export it.

In this regard, there are opportunities for additional deliveries from Georgia.

Additional Georgian export opportunities				
Contract’s volume for flow to Iran from Armenia	TWh	4.5	5.0	6.9
Additional required flow to Iran, including losses (3%)	TWh	1.28	1.80	3.76
Total Georgian export potential estimation	**TWh**	**1.53**	**2.55**	**5.31**

Thus, it is obvious that the potential of electricity deliveries from Georgia to Armenia is sufficiently large, however to realize this potential it’s necessary to ensure benefits for both sides.

The benefit of Armenia can be achieved due to part of generation on TPPs on free of charge gas, ensuring Iranian gas in other sectors of the economy by prices that less than the replaced Russian gas, ensuring return on investment in the development of the transmission system.This can be achieved by appropriate import prices (see below).

Benefit of Georgia is the ensuring such prices for the electricity export that would be attractive to private investors in hydropower in Georgia.

An additional advantage for Georgian export in this direction compared with the Turkish is a possibility to deliver electricity regardless of the seasons and hours as well as in the Armenia-Iran contract the respective volumes are considered only.This is especially important bearing in mind that most of the planned to construction HPPs in Georgia are the "run of river".

Let us consider possible prices that satisfy both sides.

As a criterion of marginal price the condition that the equivalent price of Iranian gas to Armenia should be lower than the Russianwill choose.

In this case we have

$$Tm_{arm\text{-}iran} = Pgas_{rus} * (1\text{-}L\%/100) / Ke \qquad (1)$$

where$Pgas_{rus}$ – gas price on Russia-Armenia border;
$Tm_{arm\text{-}iran}$- marginal price on Armenia-Iran border;
L% -electricity losses percentage in Armenian transmission system;
Ke – electricity / gas exchange ratio according Armenia-Iran contract

The marginal price on Armenia-Georgia border can be estimated by the formula

$$T_{GEOm} = Tm_{arm\text{-}iran} – T_{B2B} – T_{TR} \qquad (2)$$

$$T_{B2B}=Costs_{B2B} / E \qquad (3)$$

whereT_{GEOm} – marginal price on Georgia-Armenia border;
T_{B2B} – price component due to B2B link;
$Costs_{B2B}$– annual costs of B2B link;
E – annual flow through B2B;
T_{TR} – transmission tariff in Armenia, including new 400kV line to Iran or transit tariff

Let us consider, as an option for estimating the construction of B2B on voltage 220kV and 250MW capacity.

This choice is dictated by the fact that in the next few years, Georgia will not have such a surplus to provide supplies for which it would be restriction of transfer capability of existing 220kV line.

In any case, the Armenian side has already decided that if the construction will be realized, it will be implemented by stages (it is assumed that B2B will be built on the territory of Armenia close to border inAyrum).

With3% losses andKe = 3 with the Russian gas price $ 270/tcm we have a marginal price at the border of Armenia-Iran $ 87.3/MWh.

To evaluate the possible Georgian export prices the level of 2017will be accepted.This is a preliminary estimation, the actual calculations will be carried out later in the refinement the original data.

After the Fichtner‘s pre-feasibility study the annual costs necessary to recover the investment has been evaluated as $ 8.5 million by TetraTech within the above-mentioned project.Even if we assume that these costs will be covered only by the Georgian exporters (export volume 750 GWh) T_{B2B} = $11.4/MWh

Current transmission tariff for domestic consumers in Armenia is about $1.5/MWh.

Iran is funding the new line of 400kV Armenia-Iran on favorable terms of return on investment.Concrete calculations were have to be made after verification the original data.However, given the expected big volumes of flows (more than 3,000 GWh per year), we can estimate that this component of the tariff will not exceed $ 4.5/MWh (high probability of a lower value).

Even if to these value add «cost of business» of the Armenian side about $5-10/MWh the price for Georgian exporters on Georgia-Armenia border will be $60-

65/MWh and possibly higher, which is an attractive price for the Georgian traders (e.g.Consolidator) and investors in hydropower in Georgia.

CONCLUSIONS

Electricity supply to Armenia is much more attractive for Georgia in terms of volumes and prices in the case with electricity flow from Armenia to Iran compared with the case when Armenia is disconnected from Iran.

In case when Georgia is disconnected from Russia it isn't necessary to build B2B the potential price of electricity supplies to Armenia will be higher (at least $ 70/MWh).

Considering the relatively big volumes, high delivery prices, the possibility of operation by smooth shapes and the lack of seasonal restrictions may turn out that the Armenian direction of Georgian export will be is even preferable than Turkish.

2.1.4 Possible trade between Azerbaijan and Georgia and through it territory with Turkey

The current electricity trade between Azerbaijan and Georgia is characterized by small daily exchange volumes (maximal flow is 50MW).

At first glance,quite a large-scale construction of new power plants in Azerbaijan may significantly change the situation. The commission of "Janub" TPP (780MW) and a second unit on "Shimal" TPP (409 MW) with an efficiency of about 52%is expected in the near future.

Electricity deliveries from Azerbaijan are possible:

- For the Georgian domestic needs (in winter);
- As export to Turkey (transit through Georgia).

In recent years the second optionbecame a priority for Azerbaijan. Power bridge Azerbaijan-Georgia-Turkey is created. For this purpose a new 500 kV line Azerbaijan TPP – Gardabani will put into operation soon.

2.1.5 Deliveries to Turkey

Obviously, for theelectricity export from Azerbaijan to Turkey the competitive prices must be ensured. It is necessary to take into account that Azerbaijan exports gas to Turkey too via the Baku-Tbilisi-Erzurum pipelineby price $ 260-280/tcm and its capacity will be increased to 20bcm per year, and to 45 in future.

Thus, a reasonable question arises. What is more profitable to export gas or electricity?

Unfortunately, not all pricing parameters are available on export of gas so we have to make some assumptions. Let us assume that the gas transit fee through Georgia is 10%.Therefore, the minimum price of gas at the Azerbaijan-Georgia border will be $ 234/tcm.

What is electricity price may be offered to the Turkish market by burning gas in Azerbaijan at the price of $ 234/tcm?

Two options will be considered:

1. export is carried out only from new combined-cycle TPPs;
2. export is carried out both by new and old TPPs

Option 1.

New TPPs (efficiency - 52%) will allow to provide the 4.7 MWh/tcm. Thus the price of the only fuel component with the minimum losses for electricity transfer to Turkey (3%) would be $ 51.4/MWh.

To estimate the remaining costs we use the data prepared by US Energy Information Administration and shown in Table.

Table Estimated Levelized Cost of New Generation Resources, 2016.

Plant Type	Capacity Factor (%)	U.S. Average Levelized Costs (2009 $/megawatthour) for Plants Entering Service in 2016				
		Levelized Capital Cost	Fixed O&M	Variable O&M (including fuel)	Transmission Investment	Total System Levelized Cost
Conventional Coal	85	65.3	3.9	24.3	1.2	94.8
Advanced Coal	85	74.6	7.9	25.7	1.2	109.4
Advanced Coal with CCS	85	92.7	9.2	33.1	1.2	136.2
Natural Gas-fired						
Conventional Combined Cycle	87	17.5	1.9	45.6	1.2	66.1
Advanced Combined Cycle	87	17.9	1.9	42.1	1.2	63.1
Advanced CC with CCS	87	34.6	3.9	49.6	1.2	89.3
Conventional Combustion Turbine	30	45.8	3.7	71.5	3.5	124.5
Advanced Combustion Turbine	30	31.6	5.5	62.9	3.5	103.5
Advanced Nuclear	90	90.1	11.1	11.7	1.0	113.9
Wind	34	83.9	9.6	0.0	3.5	97.0
Wind – Offshore	34	209.3	28.1	0.0	5.9	243.2
Solar PV[1]	25	194.6	12.1	0.0	4.0	210.7
Solar Thermal	18	259.4	46.6	0.0	5.8	311.8
Geothermal	92	79.3	11.9	9.5	1.0	101.7
Biomass	83	55.3	13.7	42.3	1.3	112.5
Hydro	52	74.5	3.8	6.3	1.9	86.4

As can be seen from this table the amount of costs (levelized capital costs, fixed O&M and transmission investment) for a combined cycle TPP will be at least $ 20/MWh.

Considering that forelectricity export to Turkey and improve power system reliability Georgia is implementing a very ambitious project (loan is about 300 million euro).

To Azerbaijan is likely to be able to achieve a relatively small transit tariff - $5-10/MWh.Of course, the advantageous price for Georgia is much higher, but it can lead to a sharp decrease of transit volume and Georgia will not win anything.

The current legislation in Turkey allows to companies registered in Turkey only to operate on market. These companiesbuying Azerbaijan electricity will be forced to take all risks.Let us assume that "cost of business" of these companies is $5-10/MWh.

The transmission costs within Azerbaijanmust be added too taking into consideration the investment in the new 500 kV line.

As a result, we can estimate that the average price of Azeri electricity on Turkish market will be $ 85-90/MWh for first option.

Option 2.

At present, the average fuel consumption per kWh (ex-Soviet standard) in Azerbaijan is 313.2 g/kWh (Azerenergy data). This is equivalent to average generation 3.65 MWh/tcm.Taking into account the above put into operation of new TPPs this figure will increaseto 3.8 MWh/tcm.

Fuel component (with losses) will increase up $ 63.5/MWh

Obviously in this case the levelizedcapital costs decrease, fixed O&M costs increase significantly, which leads to final price increase in comparison with Option 1.

With such an annual average price the competition is hard enough even in peak season (August).

In general it is possible to export only during peak hours, taking into account the flexibility of a combined-cycle TPPs.

However, the price is still more increased due to reducing the export volumes (in the table above thecostsappropriates to capacity factor=87%).

Considering that the export is carried out from TPPs it’s evident that constant deliveries are more beneficial. But for this it is necessary to reduce the offered prices. This may be achieved only by reducing the price of used gas.

An estimated the internally subsidy of gas price will be 20% and moreand this means that for Azerbaijan gas export to Turkey is more profitable than electricity..

Taking into account that the state is aAzerbaijan's energy sector owner, it is likely the introduction of gas price subsidies for generation and it means that the intended electricity export to Turkey is determined more by political considerations than economic.

Apparently this explains the agreement reached between Azerbaijan and Turkey in May 2012 about a relatively small volume of export (750GWh per year) compared with expected at the beginning of the project AGT power bridge (2-3TWh per year).

In a possible future the large impact on export to Turkey (by way of limitation) will be the policy of Russia in Turkish direction and the process of new power plants construction in Georgia.

2.1.6 Deliveries to Georgia

Delay of the construction of new power plants in Georgia leads to import increase.At present, the main supplier of electricity to Georgia in winter is Russia. AccordingtotheESCOtheimportpriceis $ 60-65/MWh.

There is an opportunity and this price growth.In this connection in 2012 Georgia signed an agreement with Armenia about so-called "emergency supplies", which are determined not only by faults in power systems, but also in terms of long-term supply.Priceinthecontractwassetat $ 66/MWh.

These prices are quite competitive compared with Turkish considering that the electricity supply for domestic needs of Georgia does not need to take into account the "costs of business" of Turkish partner and transit fees.

In addition, it is possible to supply by smooth shapeconsidering the opportunity to apply the daily regulation in Georgia due to the water accumulation at night on large hydropower plants and its drawdown during peak hours.

It is also necessary to take into account the fact that the peak consumption in Turkey is in summer, and in Georgia is in winter, which gives an additional export possibility to Azerbaijan depending on the season and the needs of each country.

2.1.7 Electricity trade between Georgia and Russia

Electricity trade between Georgia and Russia over the last years was a seasonal power exchange (Georgia exported in summer and imported in winter).

What conclusions can be made about the prospects of trade on the basis of historical data?

Export / import volumes

The table below shows the annual volume of export / import with neighboring countries as well as only with Russia.

Years	Total export (GWh)	Total import (GWh)	Total net export (GWh)	Export to Russia (GWh)	Import from Russia (GWh)	Net export to Russia (GWh)
2007	625	433	192	306	177	129
2008	680	649	31	435	561	-126
2009	749	255	494	526	154	372
2010	1524	222	1302	1073	205	868
2011	931	471	460	460	446	14
2012	528	615	-87	369	517	-148

As can be observed from the table in 2012 for the first time since 2007, Georgia has a negative trade balance (deficit with Russia in 2008 is explained by war). This is explained by the increase of domestic consumption and the lack of implementing new generating capacities. PeakexportofGeorgiawasin 2010 (highwateryear).

Let us consider the monthly historical data of trade between Georgia and Russia, which are listed below.

The first thing to note isthe significant increase of import from Russia in winter (October - March).Taking into account that according to the ESCO average purchase price of thiselectricity for domestic consumption is currently $ 60 - $ 65/MWh, the benefit ofsubstitution of the import by the construction of new power plants in Georgia is evident.

Ontheexportsidetheimplementation of a new 400kV connection to Turkey with attractive prices for Georgian exporters allows to assume that export to Russia will be decreased.

However, we should also note one interesting fact. Turkish power system peak load, unlike Georgia and Russia, is in the summer (August).Georgian export potential maximum can be realized over a period of five months (April-August) and is declining in volumes over the years.In July and August the Turkish direction is obviously favorable. However, given that in Turkey thereis enough waterduring April-June, which means more production at its own power plants, the maximum flow of Georgia (including supplies from neighboring countries) is limited by 350MW. Because of thisthe Russian direction can also be interesting in case of significant constructions of new HPPs in Georgia.

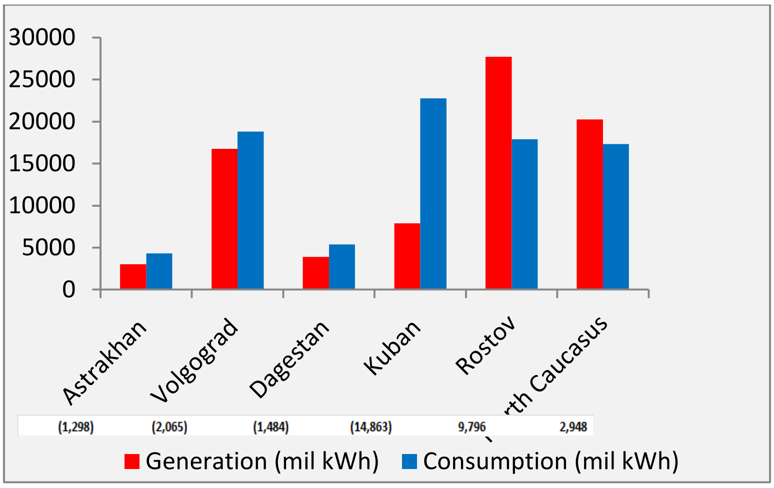
Ge-Ru (export)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
2007	0	0	0	0	0	8	143	123	7	10	3	12	**306**
2008	2	2	32	148	53	0	7	103	34	44	9	1	**435**
2009	0	28	1	0	82	121	178	100	1	12	0	3	**526**
2010	0	0	59	195	248	209	211	95	0	30	21	5	**1073**
2011	0	0	0	0	15	232	134	54	11	9	5	0	**460**
2012	0	0	0	0	76	188	82	18	4	0	1	0	**369**
Ru-Ge (import)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Year**
2007	0	0	0	0	0	0	0	4	2	40	65	66	**177**
2008	121	138	79	53	0	0	0	48	24	3	18	77	**561**
2009	0	25	0	1	4	0	3	3	3	0	43	72	**154**
2010	11	0	14	0	1	2	2	1	0	44	62	68	**205**
2011	77	78	22	2	0	0	7	2	16	6	97	139	**446**
2012	80	74	125	22	0	0	1	0	22	51	48	94	**517**
Ge net export	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Year**
2007	0	0	0	0	0	8	143	119	5	-30	-62	-54	**129**
2008	119	136	-47	95	53	0	7	55	10	41	-9	-76	**-126**
2009	0	3	1	-1	78	121	175	97	-2	12	-43	-69	**372**
2010	-11	0	45	195	247	207	209	94	0	-14	-41	-63	**868**
2011	-77	-78	-22	-2	15	232	127	52	-5	3	-92	139	**14**
2012	-80	-74	125	-22	76	188	81	18	-18	-51	-47	-94	**-148**

It's necessary to make a detailed study of possible supply prices to Russia.Currently, such supplies are made for two reasons:

- there is no serious alternative;
- existing Georgian HPPs produce a cheap electricity.

It's necessary to provide much higher export prices; however, they may be limited by internal factors in Russia.For example, today the wholesale prices in the North Caucasus are not determined by the market and are determined as $30-40/MWh due to subsidies, though calculations of market prices are carried out. These costs, of course, are not interesting for investors in the Georgian hydropower.

The analysis of the balance of electricity in the North Caucasus in 2012 (see figure below) shows that on annual basis only Dagestan has deficit, the rest republics of the North Caucasus have a surplus more than a deficit of Dagestan.



As can be seen from this figure the largest deficit in the South of Russia is observed in the Kuban (Sochi region).

Currently, due to upcoming 2014 Olympic Games the covering of this deficit is provided by the other regional power systems of Russia, for which large construction of transmission lines is undertaken.

In terms of new generation sources, in January 2013 360 MW Adler combined cycle TPPwas introduced, for367MW gas piston KudepstaTPP only permission was received in April 2013, but here there is serious resistance from environmentalists.

It should be noted that even with decision to reduce consumption for the Olympic Games from 1380 MW to 850 MW in May 2013, this region will remain deficient in terms of electricity.

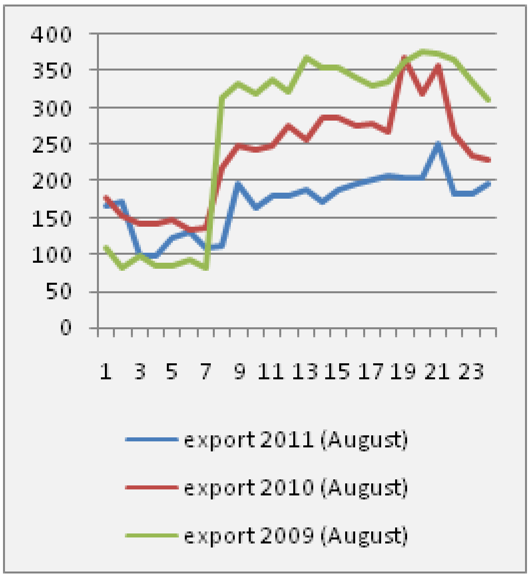
However and in this case there are certain obstacles for Georgian export.The point is that the units #3 and #4 in Rostov (Volgodonsk) NPP with a capacity of 1,000 MW each are currently under construction.Even if their launchwill be delayed (unit #3 is scheduled in 2015 and #4 in 2017) it is unlikely that at this time Georgia will introduce significant capacities on the new power plants.

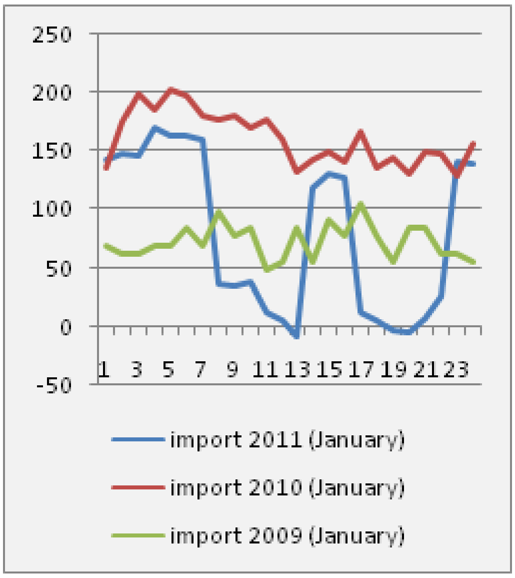
Besides, considering that although these units require a return on investment, and like all new NPPs the price of electricity should be high enough, in reality, they have the advantage of being part of the "Rosenergoatom" that integrates all Russian nuclear power plants. Therefore they can offer relatively low price (currently on domestic market the electricity price for Russian NPPs is about $40/MWh).

This price is much lower than required for new power plants in Georgia.

Inthis regard, Russia may have an interest in electricity export to Turkey through Georgia (not until appearance of these units), however the Russian policy is somewhat differentat present time. Russia invests in Turkey in the construction of 4800MW NPP,also purchased Khrami1 and Khrami2 HPPs in Georgia and plans to build another one (about 100 MW).

The analysis of historical data of Georgian export and import daily shapes is also interesting.For example, the night electricity export is much less demanded than in peak hours, while import at the night is not less than the peak capacity that allowed saving water at night on regulated power plants in Georgia.In addition, at the end of the 90s the electricity pricingbetween Russia and Georgia assumedconsiderably low price at night in comparison with peak (perhaps a similar system is used now). The planned HPPs in Georgia are mainly «run of river» and from the point of view of the winter import substitution are convenient enough.



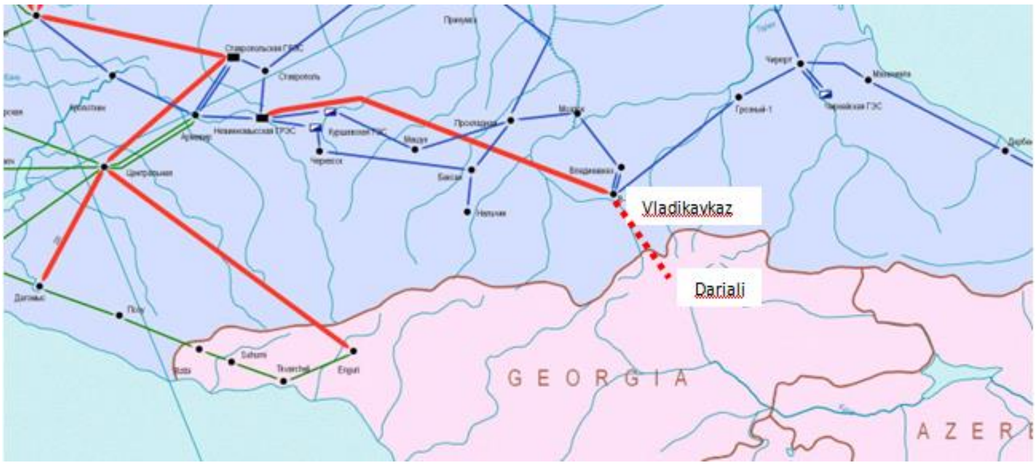


Networkdevelopment

Georgia is now connected to Russia by 500kV lineKavkasioni, 220kV lineSalkhino (through Abkhazia), and two110kV lines Darialiand Java.The last two lines can be used in island mode (transfercapacity up to 30 MW).

500 and 220 kV lines have a transfer capacity much more than the possible flows (even in a peak 2010 year the flow by Kavkasioni did not exceed 500 MW).

The possible new lines construction is mainly due to the construction of 109MW DarialiHPP. The construction of a 500 kV line Dariali–Vladikavkaz (only one 500 kV substation in this region of Russia, see Figure below) has even been discussed. The length of this line could be 40-50km, however, it will be necessary to build the 500kV substation at Dariali plant that would lead to the impossibility of return on investment.The extension of this line to Ksani is additionalmore than 150km.Initially it is obvious that this project is not effective taking into account also that there is no deficit in Vladikavkaz region.



The same conclusion may be reached by considering the 330kV option.

The most probable is the option with 220kV line construction to Ksani which will allow to cover the growing domestic load in Georgia, as well as to participate in the export to Turkey.

<u>Conclusions</u>

In the coming years the volume of Georgian exports to Russia will be significantly reduced.

Ensuring the import substitution is an incentive for investors in Georgia taking into account the significant required volumes and high prices for electricity import from Russia in the winter.

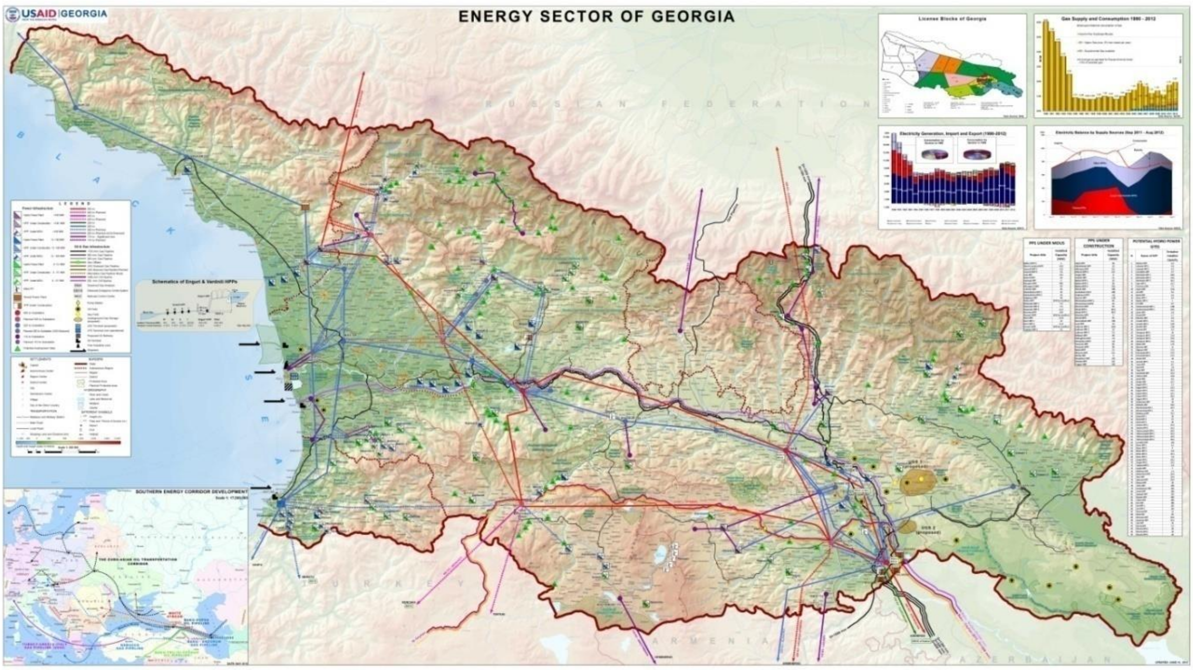
The export to Russia is less effective than to other neighboring countries for new HPPs in Georgia in summer time.

The transfer capacities of the existing lines between Russia and Georgia are sufficient enough for possible exchanges till 2018-2020 and maybe longer.

2.1.8 Georgia –Turkey trade

There are many studies regarding Georgian export to Turkey. For this purpose known large-scale network construction is nearing completion:

- SS 500/400/220 kV Akhaltsikhe with B2B converter 2x350 MW;
- 500 kV lines Gardabani-Akhaltsikhe and Zestaponi-Akhaltsikhe;
- 400 kV line Akhaltsikhe-Borchka (Turkey)



In all these studies a big export (including transit) to Turkey was considered what was to provide an incentive for investors in hydropower in Georgia.In all cases only positive factors, such as high prices for the Turkish market was considered. The extension of capacity of B2B to 1050MW was envisaged.

However, there are several constraints to export and construction of new power plants in Georgiaboth.

In none of studieswere not carried out an integrated analysis of the task, namely, the processes taking place in Turkey were not considered.

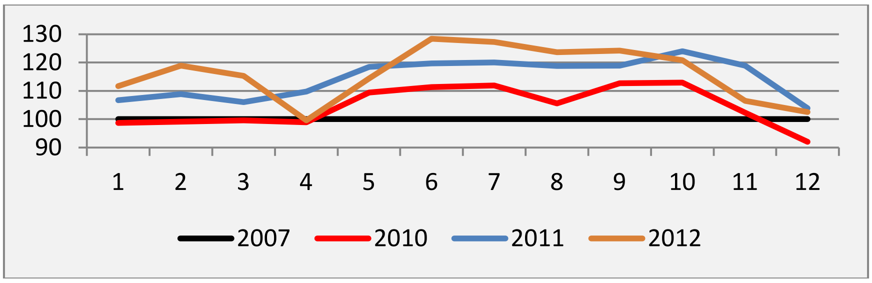
This study deals with the analysis of the problems and the possibilities of trade between Georgia and Turkey determination taking into account the current realities.

2.1.9 Consumption growth in Georgia and export potential

The domestic consumption growth has great impact on export potential in Georgia.So, in 2012, for the first time since 2007, Georgia has become a netimporter instead of net exporter.

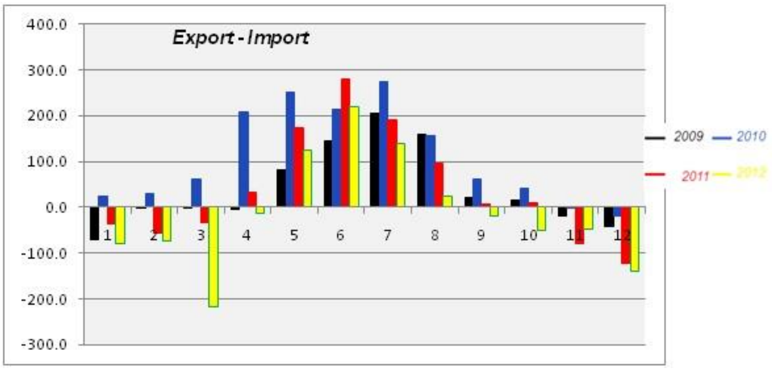
The load growth by month in relation to 2007 is shown on Figure below (data for 2008 and 2009 are unrepresentative due to war and crisis), where rapid growth of summer load (export season) in relation to winter load (import season) is visible. Here and later used historical data are the data from ESCO's website.

Load growth by months in % to 2007



As can be seen from the following figure potentially Georgian export is possible from April to August.

Georgian net export by months in GWh

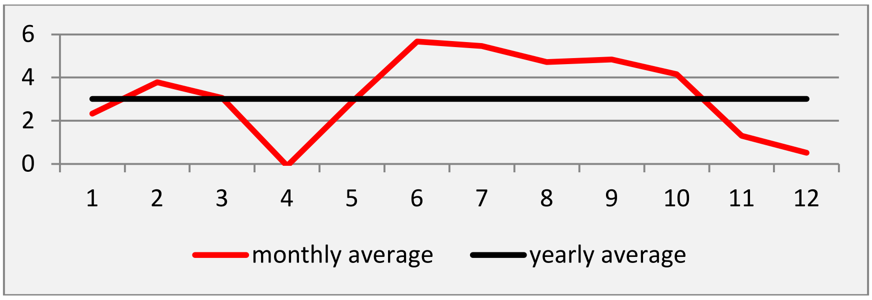


To determine the export potential taking into account new capacities commissioning delaythe average annual generation of the existing power plant for these months can be determined.

	Hydro generation in Georgia					GWh
	April	May	June	July	August	5 month
2010	922	927	844	957	811	**4461**
2011	638	894	963	922	832	**4249**
2012	603	825	947	909	718	**4002**
Average	***721***	***882***	***918***	***929***	***787***	***4237***

Load growth average annual percentage (2007-2012) amounted to 3%, although the summer% is growing more than winter (see Fig.).

Load growth average percentage by months



At such growth after 2015 in Georgia the export potential from existing HPPs will be close to 0.

	April	May	June	July	August	5 month
Export potential with historical montly load growth in % - 2013	25	187	175	139	11	**537**
Export potential with historical montly load growth in % -2015	26	147	89	50	-64	**248**

Even if we use the average annual percentage growth for the summer months by 2017 exportperiod is narrowed up to three months and export volume does not exceed 260 GWh per year.

	April	May	June	July	August	5 month
Export potential with historical average annual load growth (3%) - 2013	3	186	194	157	24	**565**
Export potential with historical average annual load growth (3%) - 2017	-87	99	103	60	-73	**103**

It is necessary to note one important fact.Georgia operates in parallel with Russia and exports summer electricitythere.This synchronous operation allows Georgiato improve the reliability of the power systemsignificantly.Furthermore, thefrequencycontrolproblemisfacilitated.

For this case, the minimum flow through 500 kV Kavkasioniline is defined of 30-50MW and if Russia will not export to Turkey (see section 3.3) and Georgia is completely reoriented on Turkey this line can be disconnected with all negative consequences.

Thus, the possible Georgian export to Turkey may be reduced by the volume of deliveries to Russia.

Georgian export and Azerbaijani transit volumes show that currently the construction of any new power plant in Georgia will not be limited by the possibility of supply to Turkeyeven during "restrictive" period from April to June (restriction is 350MW due to high water season in Turkey).

2.1.10 Factors in Turkey affecting on the Georgian export

These factors can be divided into two groups: technical constraints and price parameters.

Networkconstraints

In Turkey, the main load falls on the central and especially western parts, while the eastern part (connection point with Georgia) has low consumption.At the same timein this part of Turkey's the huge construction of HPPs is planned (about 6000MW).Currently, Muratli (115MW) andBorcka (300 MW) are working, Deriner (670MW) is building,Yusufeli (540MW) and Artvin (332MW)are scheduled for construction.

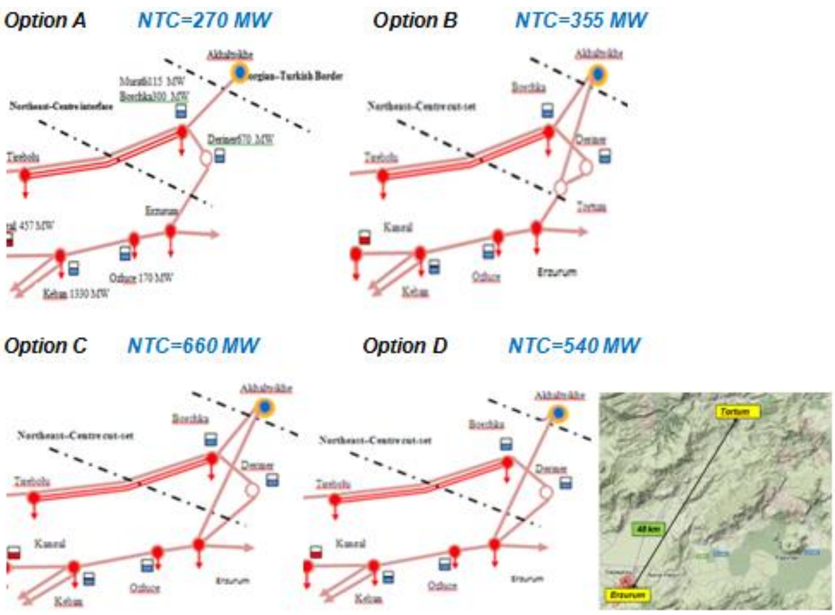
So far, the flow is directed from the center to the east, however,the situation will change withDerinercommissioning and import from Georgia,.

In this regard, the estimated calculations for transfer capabilities of East-Center interface was performed.Obviously, the this interface transfer capability primarily will affect on Georgian export.

This interface consists of lines Deriner-Erzurum (400kV) and 400 kV and two 154 kV lines Borchka-Tirebolu (see Option A on Figure below).

At normal scheme planned in the first years flow from Georgia (650MW) can be provided, however, according to EU requirements Net Trahsfer Capacity is determined whenr at least one line is tripped.So weak point of this interface is a 400kV line Deriner-Erzurum.Disabling it (repair or fault) the flow from Georgia is limited to 270MW in case when Turkish HPPs are fully loaded.

The Turkish HPPs unloading in these regimes can be carried out only when the possibility of water accumulation in the reservoirs and regime profitability exist.OtherwiseGeorgianexportwillbelimited.



In case of mentioned line disconnection it is possible Akhaltsikhe-Borcka line disconnection (by automatics) too.At the same time, in case with large flow to Turkey the Georgian power system formed a large capacity surplus and, in this sense connection with Russia is very important.Otherwise, Azerbaijan-Georgia linkmust be tripped immediately that will helponly in the case with a relatively large flow from Azerbaijan in pre-faultregime.

Akhaltsikhe-Borcka line disconnecting also leads to the same consequences for Georgia.In this case, is necessary either use phase segregated tripping (the most short-circuits are single-phase) or consider the possibility of building a second line from Georgia to Turkey.

At present time the construction of 400kV line Akhaltsikhe-Tortumis planned.However, calculations show that it can increase the NTC just to 355MW (all calculations are in accordance with EU requirements) and hardly economically expedient (Option B).

A significant NTC increase can be achieved by construction Akhaltsikhe-Erzurum line instead of Akhaltsikhe-Tortum (Option C). This will ensure the Georgian export independence from Turkish HPPs regimes. The absence of weak line Tortum-Erzurum in “Georgian export scheme” and work on extensive networks allow to increase NTC to 660MW. Of course, in this case it is necessary to find a route (in a straight line it is only 48 km.).

To costs conserve the option of 400kV line point of connectionfromBorcka to Erzurum change must be considered (Option D).This would increase NTC to 540MW (only 120MW less than under Option C).Since in this case is only one line, it is necessary to use the phase segregated tripping.

The development plans of Turkish power system the construction of a new 400kV Borcka-Kebanline is provided, however, it is clear that its construction will go in parallel with the construction of new Yusufeli and Artvin HPPs. Calculations show that this line does not allow to remove the above-mentioned restrictions on Georgian export.

Prices

Under current legislation only registered companies in Turkey can participate on the wholesale market. This means that export from Georgia will go through an intermediary with its «costs of business». These costs can be quite large, given that the partner takes all risks associated with the Georgian electricity placing on the market.

These risks primarily include:

- Big difference in prices at the night and at the peak on Turkish market takinf into account that mostly new Georgian HPPs are “run of river”;
- The need to consider congestion management problem on Turkish market.

Turkish trader desire to maximize profit with risk management can lead to significant differences between average prices on Turkish market and for Georgian electricity on border.

The new plants in Georgia will produce relatively expensive electricity (the need for return on investment) and in this regard the flow increase can be expected only when the difference between generation costs including transmission and possible prices on border is present.

In this regard the transmission tariff for exportersis very important. The initial estimation (separate study) shows that in the first few years in Georgia an export tariff based on «cross border facilities using» methodology can't be implemented because even when only costs for B2B and line to Turkey are taken into account the value is significant (more $20/MWh when Azerbaijan uses transit tariff $5-10/MWh) that will be a barrier for investors in hydropower.

Unfortunately but it should be noted that in this case all additional financial burden of a new network construction will be on the domestic consumers.

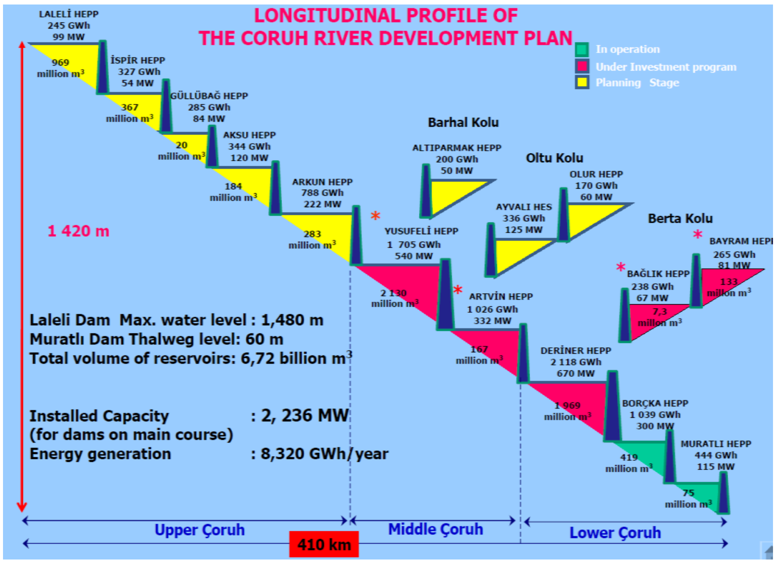
2.1.11 Georgian import from Turkey in winter

Most months of the year, Georgia has to import electricity and import will still continue to grow.

In fact a monopolist of import is Russia, and prices have already reached $ 60-65/MWh.

The construction of large hydroelectric power stations in eastern Turkey with big reservoirs with annual regulation, practically ready network infrastructure to Tbilisi makes it very probable the electricity supply in the winter to Georgia instead of Russian deliveries or for old Georgian TPPs' generation replacement.

The figure below presents data on plans to build new power plants on one river Coruhonly (presentation[12] in Tbilisi in 2009).



In Turkey the peak load is in August, the winter load and, therefore, the market price lower, that with a sufficiently attractive prices on the Georgian market can give Turkey advantages over Russia and supply electricity to Georgia, taking into account practically no transmission costs.

The Georgian benefit is evident - import price decrease or at least will grow only by objective reasons.

[12]CoruhRiver Development Plan.UbeydSezer, International Workshop on Transboundary Water Resources Management. Tbilisi, 2009.

USAID Hydropower Investment Promotion Project (USAID-HIPP)

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