Georgia's Hydropower Sector
Friendlier rules, strong prospects

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Georgia's hydropower sector holds ample development potential. The launch of a 400kV transmission line with Turkey and initiatives to harmonize the Georgian market with Turkey are key steps that position Georgia well to become an important regional energy player. We believe Georgia will increase hydropower output 41% to 11.5TWh by 2021. Given domestic consumption growth, a large chunk of this additional generation capacity could even be absorbed domestically. For 5 years up to 2012, Georgia was a net exporter of electricity, but low water levels and increased domestic consumption cut exports in 2013 and demonstrated the need for additional generation capacities. However, the Enguri hydro plant has signed an agreement with a Turkish party to sell 200GWh this summer (at US¢ 7.5/kWh), which signals a return to export markets after a poor 2013. Electricity prices remain stable, while new HPPs can now benefit from 10-year off-take tariffs for 20% of produced volumes with the Georgian market operator and priority access to the newly commissioned Turkish line.

With total investment of c. US$ 350mn, the completion of the 400kV Akhaltsikhe – Borçka transmission line is a major step towards harmonizing Georgia's electricity sector with Turkey's and Europe's. In December 2013 Turkey and Georgia additionally agreed to study the construction of a 400kV Tortum – Akhaltsikhe transmission line. Turkey is also set to become a member of the European Network of Transmission System Operators for Electricity (ENTSO-E), which would create an opportunity for Georgian electricity traders to directly access Eastern European customers. Another 500kV line to Armenia is under construction and Georgia's transmission capacity to Russia is expected to nearly double to 1,480MW by 2020, according to our estimates, after a new 500kV line becomes operational.

The expected electricity deficit in Turkey is tightening, but the market remains attractive for Georgian exports. The Turkish Electricity Transmission Company (TEIAS) has cut projected electricity consumption growth rates for 2014-2021 from a 7.0% CAGR to 5.5% and raised its projection for 2013-2017 electricity generation growth rates from CAGR 2.5% CAGR to 5.9%. Half of this expected growth in generation comes from new thermal power plants powered by natural gas (with gas costs of c. US$ 400 per cubic meter) and coal. TEIAS' new generation assumptions seem optimistic, in our view, and we expect Turkey will continue to import Georgian electricity for two main reasons: seasonality and price. Turkey experiences an electricity deficit during the summer months when Georgia produces excess hydropower, and the price of Georgian electricity exported to Turkey compares favourably to other countries. In 2012, only the Czech Republic provided Turkey with cheaper electricity than Georgia (US¢ 5.3kWh vs. US¢ 6.8kWh from Georgia; 2012 average: US¢ 7.7kWh).

Total Georgian electricity exports fell 3x from 1.5TWh 2010 to 0.5TWh in 2013 due to lower HPP generation as a result of a drier year with low water levels and higher domestic consumption. This caused a domestic deficit and drove imports. A return to average weather conditions and water flow rates and the commissioning of new, previously delayed HPPs will build up capacity and Georgia will resume exports in 2014. For example, the Enguri HPP signed an agreement to export 200GWh to Turkey in June-August as high water levels are driving expectations of surplus energy production in summer 2014. We expect Georgia will become a marginal net exporter of 0.1TWh as of 2016.

The government has launched several initiatives to support the sector. USAID's Georgian Electricity Market Model 2015 (GEMM 2015) aims to harmonize Georgia's market rules with Turkey's to allow day-ahead market operations and offer exporters more transparency in setting prices. An agreement is also in place to develop the Geographic Information Systems (GIS), which will consolidate hydro-meteorological data in digital form and allow users to manage water resources more effectively.

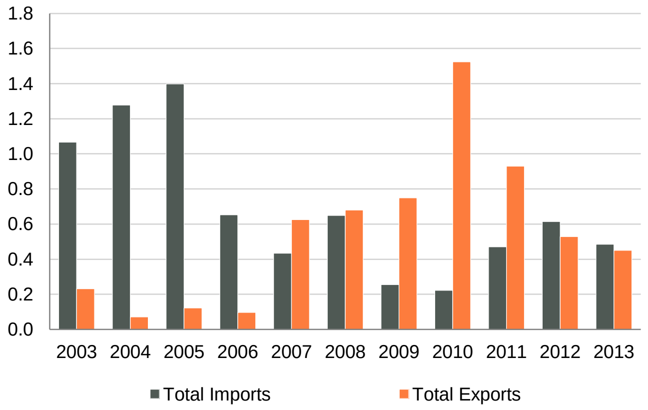
Contents

Net importer on lower generation, higher domestic demand

Georgian HPPs' electricity generation volume grew 15% y/y in 2013 to 8.2TWh. This helped reduce the consumption of more expensive, gas-powered thermal electricity from 2.4TWh in 2012 to 1.7TWh in 2013. Nevertheless, the increased generation from HPPs was not enough to bring Georgia's balance to a net export position in 2013, and 0.5TWh of electricity was imported, mostly from Russia (95%).

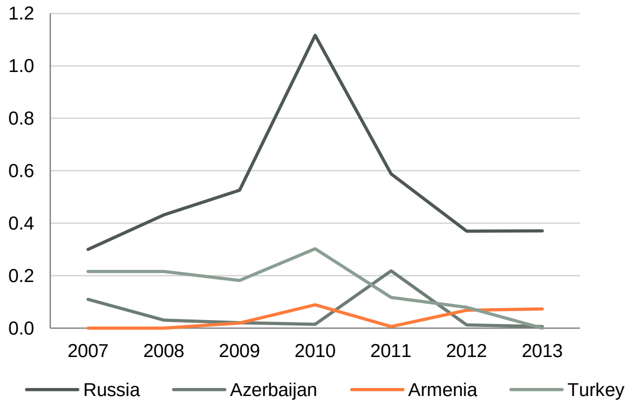
Georgia reverted to being a net importer in 2012 for the first time since 2007. Total exports fell 3x from 2010 to 0.5TWh in 2013. The main drivers were a drop in generation from both regulated (e.g. Enguri and Vardnili HPP) and seasonal (e.g. Vartsikhe and Gumati) hydropower plants (HPPs) as the snow cover thawed later than usual. Total electricity generation declined 6.3% while domestic demand grew 1.3%.

Figure 1: Georgia's electricity trade, 2003-2013, TWh



Source: ESCO

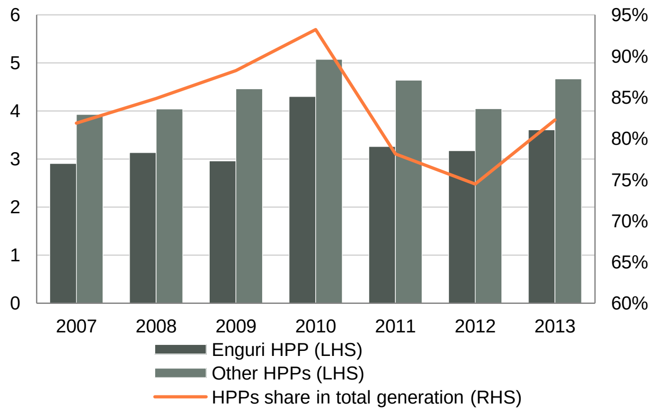
Figure 2: Electricity exports by destination, TWh



Source: ESCO

The weather-driven decline in HPP generation is temporary and higher volumes are expected in 2014. The Enguri HPP signed an agreement to export 200GWh to Turkey in June-August as high water levels are driving expectations of surplus energy production in summer 2014. We expect Georgia will once again become a net exporter of electricity, just barely, in 2016.

Figure 3: Georgian HPP generation, 2007-2013, TWh

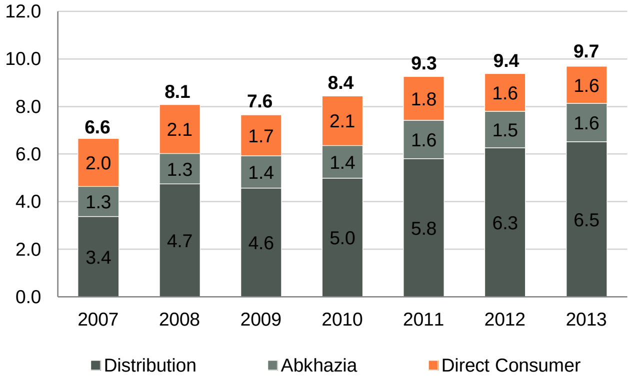


Source: ESCO

Domestic electricity consumption continues to rise, reaching 9.7TWh in 2013. However, the growth rate decelerated from 9.7% in 2010 and 2011 to 1.3% and 3.3% in 2012 and 2013, respectively. This was in line with slower real GDP growth rates, which came down from 7.2%

in 2011 to 3.2% in 2013. We expect domestic consumption to accelerate in the near-term along with projected higher real GDP growth rate of 5.0% in 2014 and 2015 (by IMF and the government).

Figure 4: Domestic electricity use customer type, TWh



Note: Abkhazia (disputed territory) retains a special customer status and has a right to consume a share of electricity from Enguri HPP for free

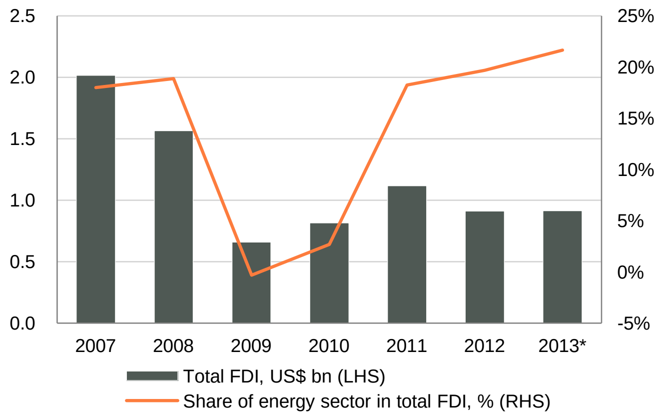
Source: ESCO

The growth in electricity consumption growth was concentrated mainly at two distribution companies – Energo Pro and Kakheti Energodistribution. Their consumption increased 18% and 12%, respectively, over the past two years. We believe the growth was not driven by the 10% reduction in electricity tariffs for retail consumers in 2013; the tariffs were only reduced for the lowest consuming segments of consumers. If anything, the reduced tariffs would have incentivised households to decrease use and pay the tariffs of the lower (below 100kWh) segment. We believe the main driver for the growth of household consumption is the catch-up effect of Georgian households purchasing electronic appliances such as air conditioners for the first time.

HPP construction behind schedule; reforms provide a boost

Energy remained the most attractive sector for foreign investors, bringing in the highest share of FDI in Georgia in 2012 and 2013: 20% and 22%, respectively. In absolute terms, energy sector FDI increased 10% y/y to US$ 198mn in 2013. Investors based in Azerbaijan, the Netherlands, and the Czech Republic were the largest contributors to energy FDI over 2010-2013, investing a combined US$ 425mn of the total US$ 603mn.

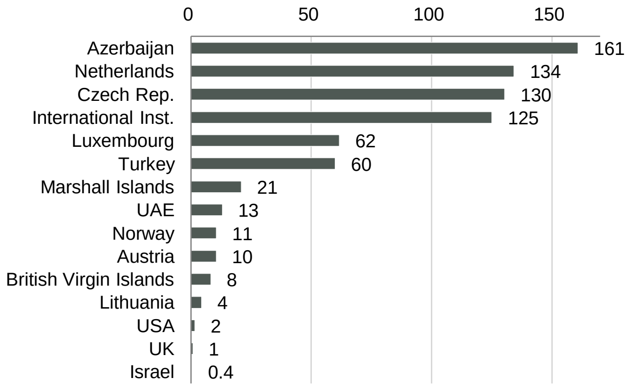
Figure 5: FDI in the Georgian energy sector 2007-2013



Source: GeoStat

** 2013 figures are preliminary*

Figure 6: FDI in energy sector by country of origin, 2010-2013 (US$ mn)



Source: GeoStat

Note: 2013 figures are preliminary

HPP construction activity has been on the rise lately, but fewer-than-expected plants have actually been completed. MoUs for 33 projects (8.5TWh of combined generation capacity) have been signed and are either in the licensing or construction stage. Feasibility studies are being conducted on another 32 projects of 7.8TWh generation capacity. These 32 projects represent around a 95% potential increase from current total HPP generation capacity of 8.2TWh. Since 2012, few plants were completed due to more requirements for environmental studies and a lack of funding as investors awaited post-election clarity and an orderly transition of power in 2012-2013.

New legislation has enabled a modification or extension on several HPP memorandums which encountered difficulties and the government has been flexible in aiding investors work towards finishing projects. For example, the government extended the original deadlines for the completion of the Kintrishi and Nabeghlavi HPPs. Also, as per the original MoUs, investors have to provide a construction-related bank guarantee to the MENR (US$ 100,000/MW for HPPs under 100MW and US$ 50,000/MW for over 100MW) which is to be forfeited in the event of missed deadlines. The government has been considerate and switched to charging daily penalties instead of charging full bank guarantee amounts on some projects (Kintrishi, Bakhvi 3, Nabeghlavi).

New legislation passed in 2013 aims to improve the incentives for HPP construction. The winners of auctions for existing potential projects need to provide a construction-related bank guarantee to the Government of Georgia of US$ 100,000/MW for HPPs under 100MW capacity and US$ 50,000/MW for HPPs with over 100MW capacity. The previous requirement was US$ 170,000/MW regardless of capacity.

Table 1: Pipeline of hydropower plants in the licensing or construction stages

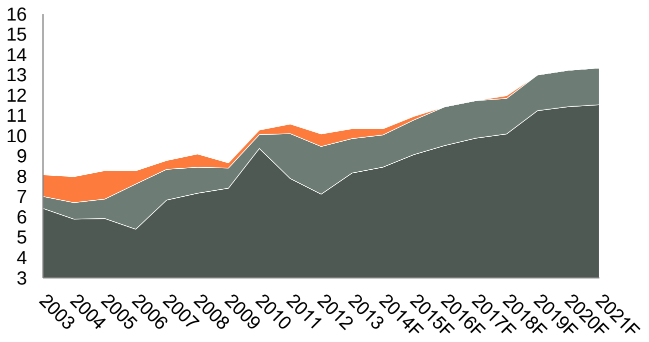
Country	Company	Project name	Capacity, MW	Annual generation, GWh	Construction Start Date	Construction Completion Date	Investment, US$ mn
Czech Republic	Wind Energy Invest	Paravani WPP	50	70	May 2013	Nov 2014	70
Georgia	AE-SGI Energy I	Nabeglavi HPP	2	13	Feb 2012	Mar 2014	3
Georgia	GC Fund	Mtkvari HPP	43	200	Dec 2009	Sep 2015	65
Georgia	Energo Aragvi	Aragvi HPP	8	50	Feb 2012	Feb 2015	11
Georgia	Georgian Investment Group	Khobi HPP 1	47	247	Nov 2014	Nov 2017	81
Georgia	Georgian Investment Group	Khobi HPP 2	40	221	Dec 2011	Apr 2015	65
Georgia	Yazbegi HPP Ltd	Yazbegi HPP	5	30	Oct 2012	Aug 2014	3
Georgia	Hydrolea	Debeda HPP	2	11	Oct 2013	Jul 2014	2
Georgia	Hydrolea	Pshavela HPP	2	10	Oct 2013	Jul 2014	2
Georgia	Alter Energy	Okropilauri HPP	2	9	Sep 2012	Oct 2015	1[1]
Georgia	Alter Energy	Goginauri HPP	2	9	Sep 2012	Oct 2015	1[1]
Georgia	Hydro Development Comp.	Kintrishi HPP	5	30	Apr 2014	Oct 2016	8
Georgia	Partnership Fund	Nenskra HPP	210	1,300	Mar 2014	Mar 2019	570
Georgia	Svaneti Hydro Ltd	Mestiachala 2 HPP	20	85	Apr 2015	Apr 2017	33
Georgia	Partnership Fund	Tsageri HPP	110	570	Jul 2012	Feb 2017	200
Georgia-USA	Dariali Energy	Dariali HPP	108	521	Nov 2011	May 2014	135
India	Trans Electrica Ltd	Khudoni HPP	702	1,500	Mar 2014	Nov 2019	777
Norway	Clean Energy	Koromkheti HPP	150	463	Jul 2015	Apr 2020	250
Norway	Clean Energy	Skhalta HPP	10	27	Jul 2015	Apr 2020	10
Norway	Clean Energy	Shuakhevi HPP	175	437	Oct 2012	Apr 2015	290
Norway	Clean Energy	Khertsivi HPP	65	239	Jul 2015	Apr 2021	N/A
Turkey	Adjar Energy	Khelachauri HPP 1	47	230	Jan 2012	Dec 2016	70
Turkey	Adjar Energy	Khelachauri HPP 2	29	129	Jul 2015	Jun 2018	69
Turkey	Adjar Energy	Kirnati HPP	35	154	Jan 2012	Dec 2016	57
Turkey	KGM	Bakhvi HPP	45	158	Jan 2015	Jan 2018	85
Turkey	KGM	Bakhvi HPP 5	2	10	Oct 2012	Jul 2013	3
Turkey	Optimum Energy	Abuli HPP	20	129	Apr 2013	Apr 2015	30
Turkey	Optimum Energy	Akhalkalaki HPP	15	85	Jul 2014	May 2016	30
Turkey	Optimum Energy	Arakali HPP	11	63	Apr 2013	Apr 2015	30
Turkey	Rusmetali	Lukhuni HPP 1	11	66	May 2015	Dec 2019	16
Turkey	Rusmetali	Lukhuni HPP 2	12	74	Aug 2010	Dec 2014	18
Turkey	Rusmetali	Lukhuni HPP 3	8	46	May 2020	Dec 2024	11
Turkey	Calik Enerji	Alpana HPP	44	236	Apr 2014	Apr 2018	117
Turkey	Calik Enerji	Sadmeli HPP	125	620	Nov 2011	Mar 2016	250
Turkey	Georgian Urban Energy	Paravani HPP	78	425	Jul 2009	Aug 2015	190
Total			**2,237**	**8,466**			**3,554**
Actual completion		*40%[2]*					
Estimated completion			**894**	**3,382**			**1,420**

[1] Calculated by dividing a company's total investment equally among projects; [2] Given past project completion rates, we assume that 40% of projects currently in the licensing or construction stages will be completed

Source: MENR, Bank of Georgia Research Estimates

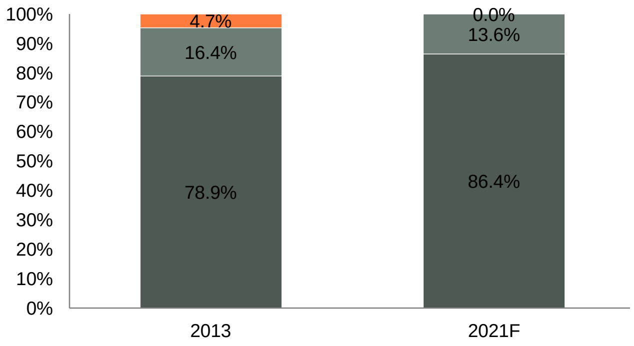
An estimated 3.4TWh (42% of the current HPP generation) of additional annual generation capacity from new HPPs should come on stream over the 2014-2021 periods. Considering historical project completion rates, we assume that only 40% of projects currently in the licensing or construction stages will eventually be completed.

Figure 7: Electricity generation development by sources in Georgia, TWh



Source: ESCO, MENR, BoG Research Estimates

Figure 8: Development of Georgia's electricity supply share by source

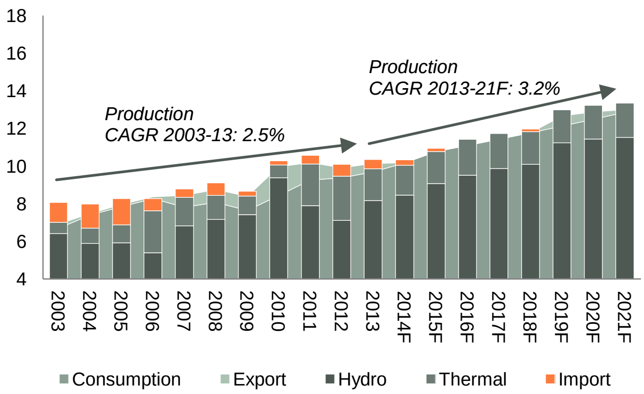


Source: ESCO, MENR, BoG Research Estimates

Even if some projects are discontinued or delayed, 30 HPP and 2 Wind Power Plant (WPP) feasibility-stage projects are waiting in the wings to replace them. Due to a lack of clarity, we exclude these projects from our projections. Overall, our projections of electricity generation capacity are subject to the uncertainty of early-stage projects, but they can be used as a proxy for estimating near-term generation capacity.

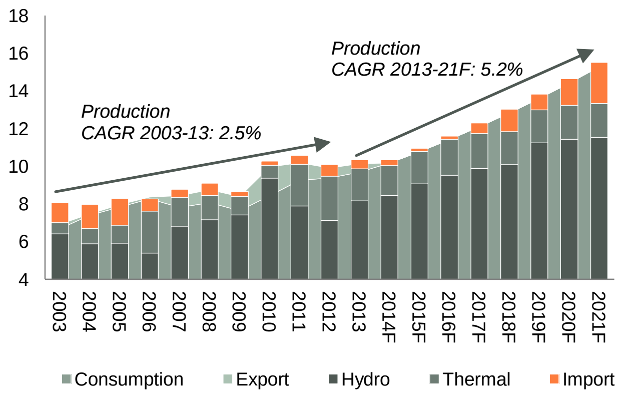
The large Namakhvani HPP project, with expected installed capacity of 450MW, was discontinued by its investor, Georgian Oil and Gas Corporation (GOGC). Instead, GOGC decided to pursue the construction of a thermal power plant, Gardabani, in a joint venture with the Partnership Fund of Georgia. Construction works have already started and the plant is expected to be operational in 2015. Gardabani alone will boost the total installed capacity of all TPPs in Georgia to 910MW from 680MW at the moment.

Figure 9: Georgia's electricity balance and export potential (base consumption), TWh



Note: Base consumption assumes 2013-2021F growth of 3.6% CAGR
Source: BoG Research Estimates

Figure 10: Georgia's electricity balance and export potential (high consumption), TWh



Note: High consumption assumes 2013-2021F growth of 5.9% CAGR
Source: BoG Research Estimates

According to our analysis, electricity generation from gas-fired TPPs will maintain its share in the range of 13% - 16% of total generation over 2014-2021 from its current 17%. TPPs provide secure supplies in the winter and help address the seasonality of hydropower generation. The additional capacities provided by the Gardabani TPP will require more gas, but it will replace existing TPPs and overall gas consumption should remain comparable at similar prices. Georgia sources most gas for TPPs from Azerbaijan and Russia:

- Azerbaijan: Supplemental and optional purchase agreements on gas transported through the South Caucasus Pipeline (SCP):
    - Supplemental: 500mmcm until 2025
    - Optional: 5% of gas transported through Georgia via the SCP
- Russia: 10% of natural gas transported from Russia to Armenia via the North-South Gas Pipeline (NSGP) as an in-kind transit fee

Currently, the weighted average gas purchase price is around US$ 143/tcm. We expect social gas prices to remain low in Georgia under stable long-term purchasing contracts, unlike Ukraine, where gas prices increased 5x after subsidized contracts from Russia ended in 2006. More expensive gas would, however, make thermal power more expensive than imported electricity. In that case, we believe Georgia would bridge excess winter demand via imports rather than through additional gas-powered TPP electricity.

Domestic electricity markets and tariffs

The Electricity System Commercial Operator (ESCO) is the market operator in Georgia. ESCO carries out three essential functions in the market that contribute to domestic tariffs:

- The facilitation of Guaranteed Capacity (reserve electricity)
- The sale and purchase of Balancing Electricity (a mechanism for maintaining the continuous balance between electricity production and consumption)
- Electricity import and export

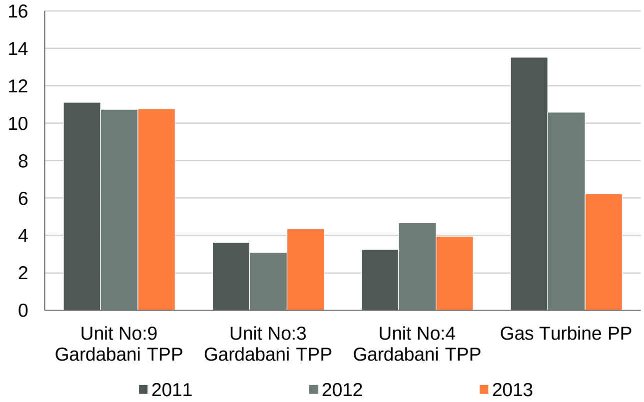
Other non-essential tasks include maintaining a database of electricity trade and inspection of wholesale meters.

Guaranteed Capacity

ESCO carries out trade in Guaranteed Capacity (GC), which is a reserve capacity provided by TPPs on a standby mode whenever there is a shortage in the grid. The TPPs agree with Georgian State Electrosystem (GSE) on the number of days they are able to connect to the network in order to stabilize electricity supplies, particularly during the winter months. TPPs can connect to the grid quickly (from 20 minutes to 24 hours) and hedge the seasonality of HPP output. The GC is provided by four TPPs and a gas turbine plant, generating a total 1.7TWh, or 17% of all electricity generated in the country.

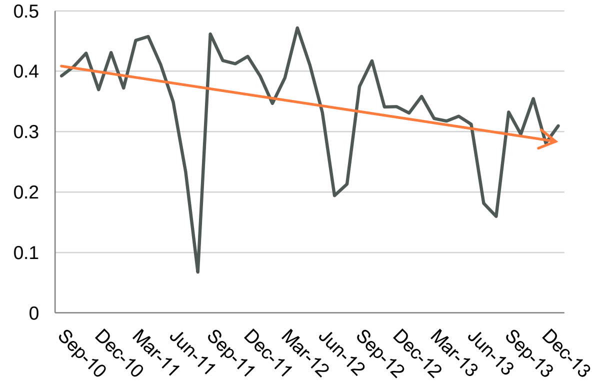
ESCO does not sell GC for a profit and applies a two-tier tariff to GC – a payment for guaranteeing capacity (a stand-by fee is paid when TPPs are idle) and a production-based payment (for actual generation). In the first case, all grid users pay proportionally for stand-by service. For the production-based payment, the grid users who consume the actual guaranteed capacity generated by TPPs pay ESCO for the volumes. ESCO pays the GC providers based on volumes generated.

Figure 11: Cost of guaranteed capacity by source, 2011-2013 (US$ mn)



Source: ESCO

Figure 12: Guaranteed Capacity price, US¢/kWh



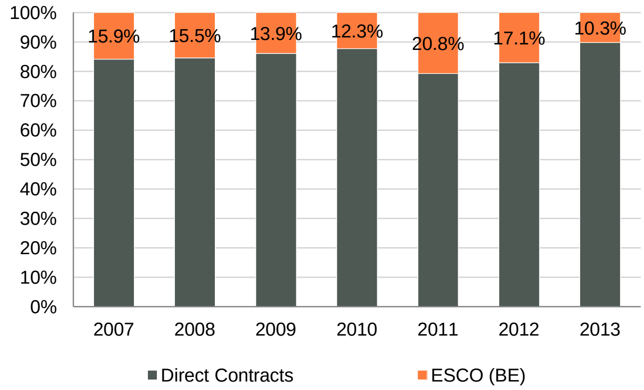
Source: ESCO

The total cost of guaranteed capacity is down 20% since 2011 (from US$ 32mn to US$ 25mn in 2013) as more HPPs provide a buffer for the system, which reduces the need for guaranteed capacity at TPPs. Other reasons for this cost reduction might be less capex/maintenance costs by TPPs (i.e. lower fixed GC cost) or higher efficiencies and less gas consumption. The Gardabani TPP will become another Guaranteed Capacity provider and will replace older and less reliable thermal generators (particularly Tbilsresi). The Gardabani launch will initially drive an increase in guaranteed electricity prices due to the higher associated costs, but the total GC fee will not exceed US¢ 7/kWh, in our view, which is in-line with current costs.

Balancing electricity

ESCO on average held 15% share in electricity trade through its trade balancing role over the last seven years. The remainder of the trade is conducted via direct contracts. Balancing electricity takes place when large consumers buy or sell capacity when direct contract capacities are insufficient. Demand typically rises in the winter. ESCO pays the providers different fees depending on its regulated status (see Appendix 3).

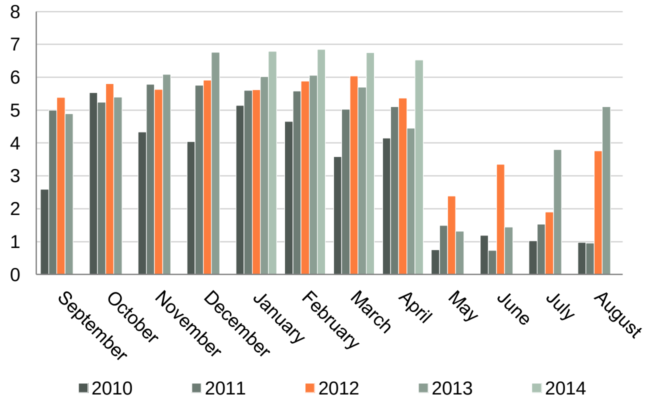
Figure 13: ESCO's share of the electricity trade



Source: ESCO, BoG Research Estimates

Tariffs are set by the Georgian National Energy and Water Supply Regulatory Commission (GNEWSRC). The GNEWSRC identifies and regulates tariffs for generation, transmission, dispatch, distribution, transition, supply, and consumption, as well as tariffs for ESCO's services, the guaranteed capacity fee, and the guaranteed capacity source's power generation tariff. Stations of over 13MW capacity built after August 2008 require a generation license, while tariffs for all HPPs built since then are fully deregulated.

Figure 14: Weighted average tariff for electricity balancing volumes sold by ESCO, (US¢/KWh)



Source: ESCO, BoG Research Estimates

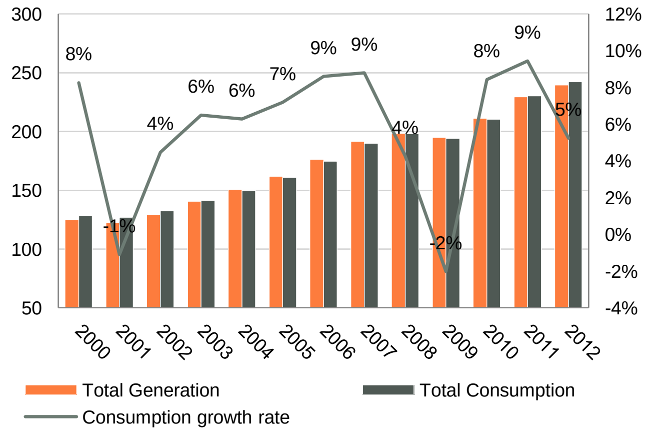
The weighted average tariff of the balancing electricity function has increased in recent years, from US¢ 4.59/kWh in April 2010 to US¢ 6.47/kWh in April 2014. Increased imports and higher tariffs by new HPPs trying to recoup initial investment costs are the main drivers of the increase.

The tariffs at which ESCO sells electricity to balance the market can be used as a reference for wholesale market prices. The monthly weighted average electricity price is relatively low in the summer, around GEL 0.04/kWh (US$ 0.02/kWh), compared to around GEL 0.11/kWh (US$ 0.06/kWh) in the winter. The spread is the result of the seasonality of hydro generation assets. HPPs get sufficient volumes of river water during the summer and are able to cover the country's needs, but are unable to satisfy electricity needs in the winter. The shortfall is covered by relatively expensive thermal power and imports.

Turkish electricity markets and tariffs

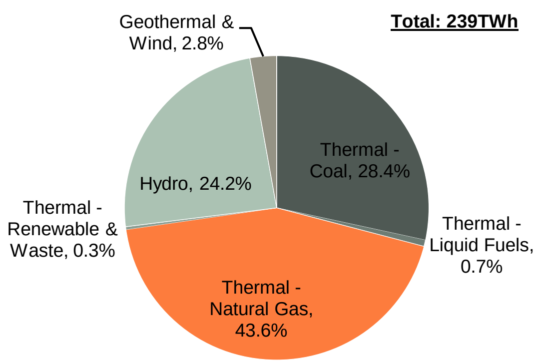
Electricity consumption in Turkey grew 9.4% and 5.2% in 2011 and 2012, respectively, reaching 230TWh and 242TWh. Thermal plants accounted for 73% in 2012, but hydropower is on the rise as new projects are completed. Hydropower generation volumes rose from 33.3TWh in 2008 to 57.9TWh in 2012. However, most of the potential HPP projects have already been developed in Turkey and further growth in hydropower generation will be very limited.

Figure 15: Electricity generation/use in Turkey, TWh



Source: TEIAS

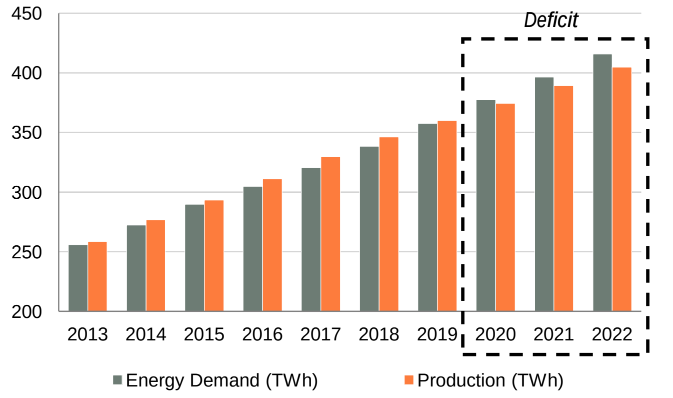
Figure 16: Turkey's power generation breakdown, 2012



Source: TEIAS

Based on 2013 projections by TEIAS, Turkey will only post a marginal deficit in 2015 under a high demand scenario. Under all other scenarios, supply is expected to exceed demand. Previously, projections had shown a significant deficit from 2016 onwards. Turkey (TEIAS) now expects to generate 350-370TWh in 2017 compared to the previous estimate of 315-320TWh, while demand forecasts were revised down to 300-340TWh from 330-350TWh. We believe the new assumptions by TEIAS are overly optimistic, and we expect electricity generation in Turkey will grow to 405TWh in 2022 from 240TWh in 2012 (69% increase).

Figure 17: Turkey's electricity supply/demand forecast, TWh



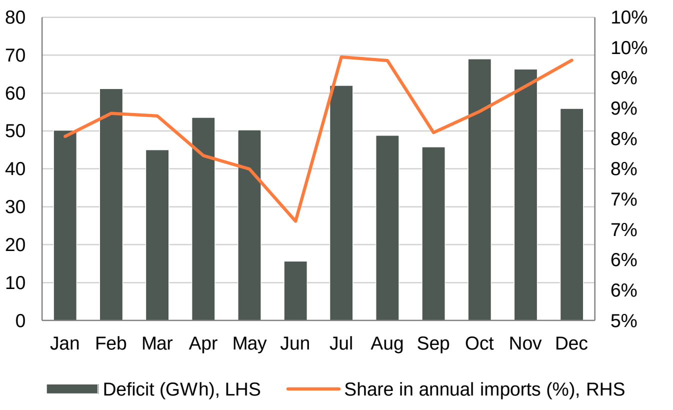
Source: TEIAS, BoG Research

Note: Demand projections are based on the average of Low and High demand scenarios as forecast by TEIAS; Supply projections are Bank of Georgia Research estimates for 2013-2022 period with an average of 5.4% annual growth

Compared to the 2011 projection by TEIAS, consumption projections have been revised downwards and generation projections revised upwards. The demand forecasts have been aligned with macroeconomic targets and a decrease in expected GDP growth rates in Turkey has fed down into a corresponding decrease in electricity consumption projections. As for generation, geothermal, coal and natural gas-fired thermal power projections for 2017 were upgraded by 58%, 52% and 16% in a new 2013 report as compared to the 2011 report. Projections for hydropower generation in 2017 were also revised upwards by 12% in 2013.

Based on our revised assumptions, we expect Turkey to post a deficit of 7TWh in 2021 and 11TWh in 2022. In addition, most of the growth in generation in the TEIAS forecasts is from thermal sources such as lignite, coal, and natural gas (15%, 13% and 50% of the 2017 total). Electricity produced from non-renewable sources is normally more expensive than hydropower, which should help Georgian HPPs export to Turkey.

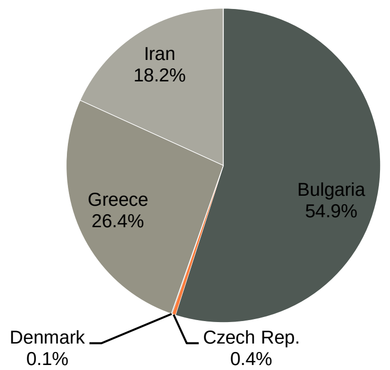
Figure 18: Turkey's electricity deficit and imports by month (2000-2012 average)



Source: TEIAS

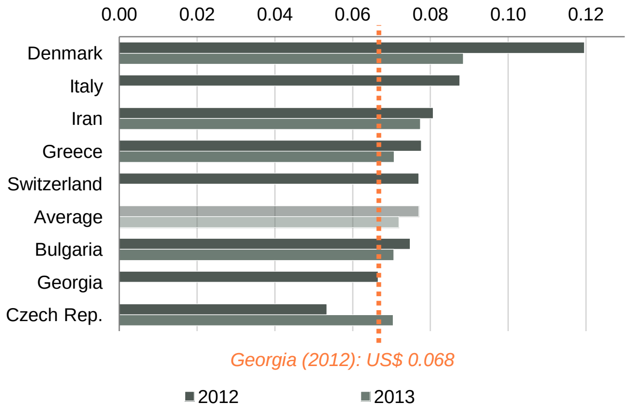
Despite new generation capacities Turkey still has shortfall, with nearly 5TWh of electricity imported in 2013 from five neighboring countries at a total bill of US$ 335mn. Unlike Georgia, Turkey's deficit comes in the summer and a significant share of imports comes in July and August. This seasonality bodes well for Georgian producers as the generation capacity of typical run-of-the-river HPPs in Georgia are at their highest during the summer months.

Figure 19: Turkey's electricity imports in 2013 by origin (Total imports: 4.7TWh; US$ 334mn)



Source: WITS

Figure 20: Prices of imported electricity in Turkey by origin, 2012-2013 (US$/kWh)

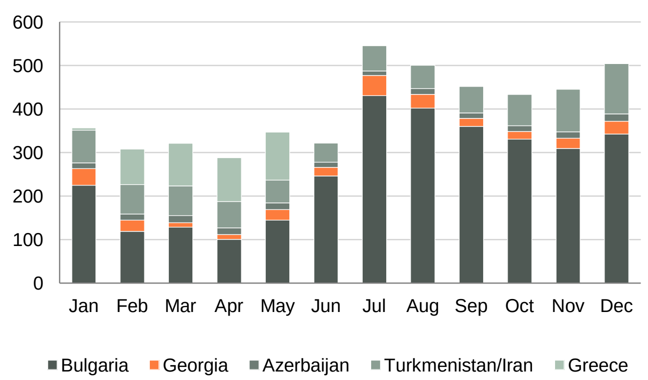


Source: WITS, BoG Research

In 2013, Turkey imported more than half of its electricity (over 2.5TWh; US$ 180mn) from Bulgaria. More than 1TWh (US$ 86mn) was imported from Greece and around 846GWh (US$ 65mn) from Iran. Turkey also purchased electricity from the Czech Republic and Denmark. Turkey's foreign trade deficit in electricity reached more than US$ 305mn in 2013, according to STI.

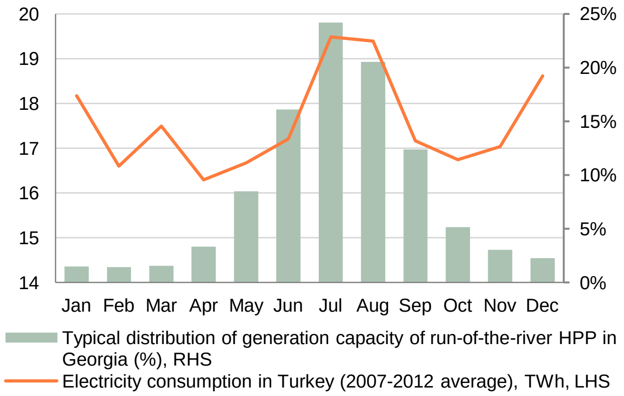
The price of Georgian electricity exports compares favourably to other countries for Turkey. The Czech Republic was the only country in 2012 from which Turkey sourced cheaper electricity than Georgia (US¢ 5.3kWh vs. US¢ 6.8kWh from Georgia). The average price of imported electricity in Turkey was US¢ 7.7kWh in 2012 and US¢ 7.2kWh in 2013.

Figure 21: Monthly average imported electricity to Turkey by country, GWh, 2007-2012



Source: TEIAS

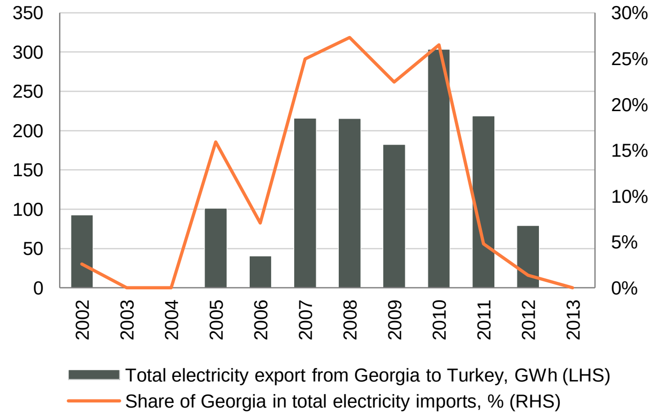
Figure 22: Electricity consumption seasonality in Turkey and HPP generation in Georgia



Source: TEIAS, BoG Research Estimates

Nevertheless, Georgian electricity exports to Turkey fell from over 300GWh in 2010 to essentially nothing in 2013, as a result of a low supply of water to HPPs in 2013.

Figure 23: Electricity exports from Georgia to Turkey, 2002-2013, GWh



Source: TEIAS, ESCO

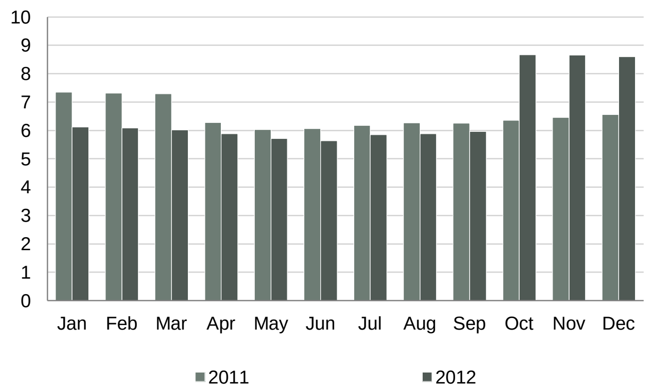
The Enguri HPP, the largest hydropower producer in Georgia, recently signed an export agreement with Turkey's Aksa to export electricity in 2014. The contract outlines a US¢ 7.5/kWh price and 200GWh of export for June-August 2014.

High electricity prices in Turkey compared to Georgia are the key motivator for HPP construction in Georgia. Prices in Turkey are generally determined in three different markets, out of which Georgian exporters currently have access to only the bilateral contracts market:

- An organized day-ahead market (DAM); Market Financial Reconciliation Center (PMUM)
- A real-time balancing market (operated by TEIAS)
- A bilateral contracts market

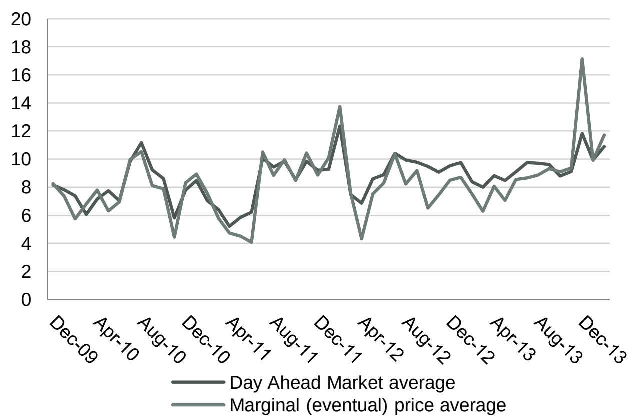
Currently, c. 71% of the Turkish market is made up of bilateral contracts, while the remaining is made up of the balancing market and the DAM. The day-ahead market, which was established December 1, 2012, is the organized wholesale spot electricity market. It allows market participants to balance their generation and/or consumption and bilateral contract obligations.

Figure 24: Monthly tariffs of EUAS sales based on bilateral agreements, (US¢/kWh)



Source: EUAS

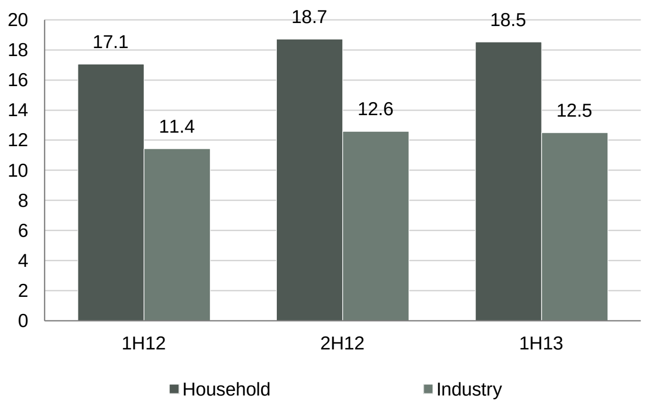
Figure 25: Turkish electricity DAM weighted average prices (US¢/kWh)



Source: EPDK

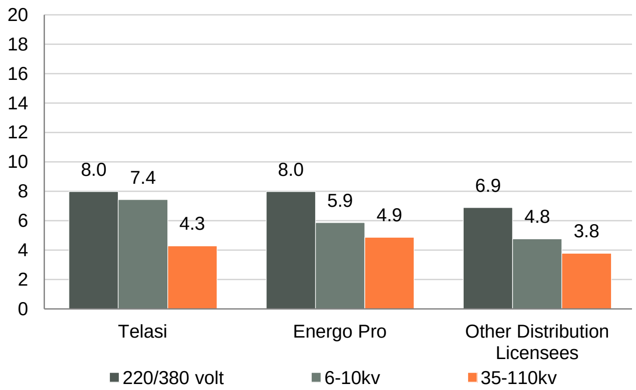
Georgian exporters can only sell in Turkey to final consumers via bilateral contracts. However, the implementation of the GEMM 2015 strategy will enable the convergence of the Georgian electricity trading system with Turkey's by establishing a DAM trading platform. It may also enable Georgian electricity suppliers to achieve better transparency and synchronization.

Figure 26: Average electricity unit prices in Turkey (US¢/kWh)



Source: TEIAS
Note: End of period FX rates of TRY 1.81/US$, TRY 1.78/US$ and TRY 1.93/US$ used for 1H12, 2H12 and 1H13 respectively

Figure 27: Electricity cap prices to households in Georgia by distributor and voltage used (US¢/kWh)

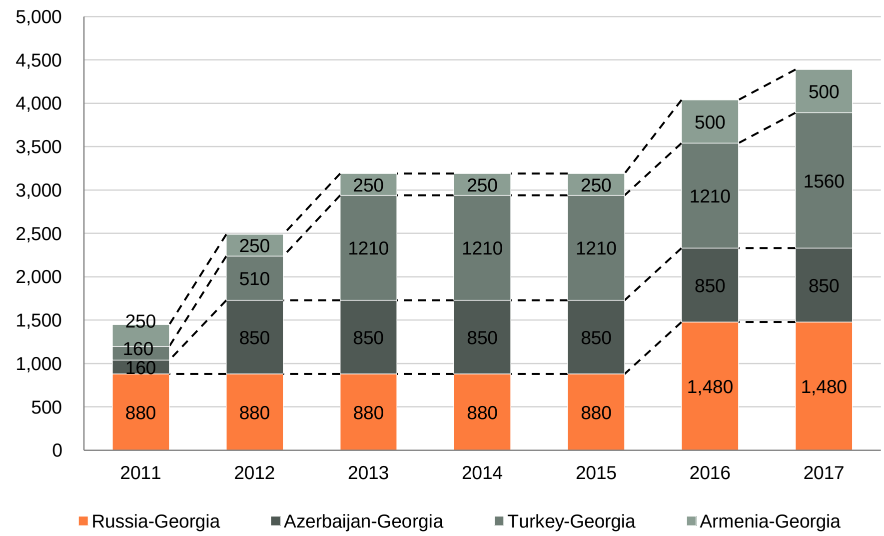


Source: GNERC
Note: Current FX rate of GEL 1.75/US$ used for conversion

Transmission capacity

The Georgian State Electrosystem (GSE) has significantly improved its transmission capacity in recent years by rehabilitating a 500kV line to Azerbaijan and building a 400kV line to Turkey. Another 500kV line to Armenia is under construction and Georgia's transmission capacity to Russia is expected to rise by 1.7x to 1,480MW by 2020, by our estimates, after a new 500kV line becomes operational.

Table 2: Cross border transmission line development, cumulative, MW



Source: GSE, BoG Research Estimates

Georgian exporters currently pay US¢ 1.2/kWh in transmission and other fees (Table 3). Most of the fees are fixed, while the System Capacity Charge, a levy on all users of the grid for Guaranteed Capacity, is determined monthly by ESCO based on GC use and TPPs' costs. The remaining fees are set by respective grid owners and monitored by the GNERC.

Table 3: Transmission tariffs in Georgia – service cost for export

	Tetri/kWh	US¢ /kWh
Dispatch Service fee - GSE	0.15	0.09
Transmission Fees		
GSE	0.50	0.29
Sakrusenergo	0.18	0.10
EnergoTrans - Internal	0.27	0.15
EnergoTrans - Export	0.35	0.20
System Capacity Charge (GC fee)[1]	0.60	0.34
ESCO fee[2]	0.02	0.01
GNEWSRC fee	0.02	0.01
Total	**2.09**	**1.19**
+ Constraint Fee[3]	*3.06*	*1.75*

[1] Variable monthly
[2] ESCO fee is rounded up from the actual 0.019 Tetri
[3] In case of capacity constraints on the Akhaltsikhe – Borçka; average winning bid for May, June and July auctions
Note: US$/GEL FX current rate of 1.75 was applied
Source: ESCO, GSE, GNERC, Bank of Georgia Research Estimates

Transmission line construction and accessibility environment

1. Access to the main grid for newly-built HPPs

Standardized procedures or legal frameworks do not yet exist for the construction of transmission lines to connect new HPPs to the main grid. This is negotiated on a case-by-case basis with the government (MENR; GSE) and is not included in the MoUs, only in a separate agreement. Since there are no standard rules and regulations, the government has been flexible and has approached each project in an individual manner. When considering whether to step in and fully finance or co-finance the construction of transmission lines for new HPPs, the government takes the following into consideration:

- **Energy security of the line:** The importance of building transmission lines for overall security is a key factor for the government in deciding where to take responsibility for financing.
- **Transmission line and grid efficiency:** The government is likely to contribute by building a transmission line if it will effectively be used to connect multiple generation sources (current or potential). Alternately, all of the power sources would build their own individual lines, which would have a larger negative impact on the environment.
- **Size of the project:** The government is more partial to projects with larger installed capacities and more difficult construction requirements.
- **Local socio-economic situation:** HPPs built in areas with high poverty and unemployment rates are more likely to secure support from the government due to their significance for the local population.

For example, the government is building the Akhaltsikhe-Batumi line, which will benefit Clean Energy's HPP projects (Koromkheti, Skhalta, Shuakhevi and Khertsivi) in Adjara region by connecting them to the main grid. The line is important because the Adjara region is currently dependant on the old and unreliable 220kV Paliastomi line; the new Akhaltsikhe-Batumi line will provide an alternative transmission route and offer the region improved energy security. In another example, the government recognized the systemic importance of the Dariali HPP (108MW installed capacity) and shouldered the cost of building the transmission line. This line also provides an alternative connection to the electricity grid in Russia to help address the instability issues with the current connection via Abkhazia.

Small HPPs usually cover the full cost of line construction, putting them at the biggest disadvantage. Line construction may prove to be an expensive exercise given the significant distance from the HPP to the grid and the average cost of construction (approximately US$

70,000/km and US$ 120,000/km for 35kV and 110kV lines, respectively). This is a sizeable upfront investment and a large amount per MW for smaller HPPs with less installed capacity. We believe it would be more attractive and feasible for investors if the government took the responsibility to construct and operate secondary transmission lines.

2. Obtaining capacity allowance on export lines

The process for gaining access to the capacity on export lines has been simplified and made more transparent, especially for the 400kV Akhaltsikhe - Borçka line to Turkey. By August of each year, Georgia and Turkey agree on the monthly capacity for the following calendar year. The capacities are then allocated in the following priority:

1. Emergencies
2. Newly built HPPs (after 2010) that have capacity reservation contracts
3. All other newly built HPPs
4. All others (Old HPPs, TPPs, transit trade)

In the case of capacity constraints within the same priority group, the GSE organizes a Capacity Allocated by Auction (CAA) process. To win in an auction, participants submit bids with offers of "constraint fees" to EnergoTrans (the line operator). After three rounds of bidding, the highest bidders are given priority and the CAA is allocated accordingly. The GSE has already held two auctions (March and May 2014) to allocate CAA for the period ending November 2014, and the bidders paid relatively high Constraint Fees (c. US¢ 1.75/kWh in May, June and July) to secure the auction allocation.

Table 4: Final bids/constraint fees paid for the Akhaltsikhe – Borcka line Capacity Allocated by Auction (CAA)

	May 2014		June 2014		July 2014		August 2014	
Amount of CAA (MW)	**84**		**284**		**269**		**65**	
	Final bid price		Final bid price		Final bid price		Final bid price	
Contestants	Tetri/kWh	US¢/kWh	Tetri/kWh	US¢/kWh	Tetri/kWh	US¢/kWh	Tetri/kWh	US¢/kWh
Eastern Electricity Ltd	2.97	1.70	3.10	1.77	3.03	1.73	0.96	0.55
Vardnili HPP cascade	-	-	3.11	1.78	3.11	1.78	-	-
Vartsikhe 2005	1.70	0.97	1.70	0.97	-	-	-	-
Enguri HPP	-	-	3.11	1.78	3.11	1.78	1.75	1.00
EnergoPro Georgia	2.90	1.66	3.11	1.78	3.10	1.77	-	-
Georgian International Energy Corporation	2.80	1.60	0.05	0.03	1.70	0.97	0.05	0.03
Georgian Water and Power	-	-	2.54	1.45	3.01	1.72	-	-
Highest bid	**2.97**	**1.70**	**3.11**	**1.78**	**3.11**	**1.78**	**1.75**	**1.00**

Note: US$/GEL FX current rate of 1.75 was applied
Source: GSE

Nevertheless, newly built and higher-priority HPPs automatically receive requested amounts without paying constraint fees as there is enough capacity for priority players. In this regard, the fees that older HPPs pay (as shown in the table above) demonstrate the appeal of exporting to Turkey; the final selling price must be comfortably above total costs, which now include an additional US$ 0.02/kWh of constraint fees.

Oversubscription to transmission lines causes uncertainty for new HPPs and can hamper fundraising efforts. With the government's help we believe this can also be solved in two ways. Firstly, the government (GSE or MENR) can commit to build a new transmission line in a given direction once the export line (e.g. to Turkey) reaches a certain level of subscription from new HPPs (e.g. 80%). Secondly, for those HPPs that secured access to export lines but cannot get capacity allocations due to line's oversubscription, the government (e.g. ESCO) can commit to compensate them for loss of revenue in such cases by purchasing electricity from them at pre-agreed tariffs, ideally similar to export prices. Given that the current landscape still has room for all new HPPs, we believe this commitment will not be a difficult one for the government, but it would offer investors additional confidence.

New government initiatives

New rules for building HPPs in Georgia came into force in August 2013. Potential investors express an interest in available projects and the winner via auction signs a MoU with the Government of Georgia, ESCO, and third parties. The agreement obliges the investors to sell 20% of generated electricity to ESCO at a guaranteed pre-determined price 10 years after the start of operations. If multiple parties qualify through the expression of interest round, the winner is the investor that offers the lowest price to ESCO for the 20% required supply. The purchase period for this 20% is agreed on in the MoU and normally covers the winter period. The initiative is intended to promote investment in the sector as it provides the stability of guaranteed off-take tariffs for 10 years. However, MENR has set a ceiling rate of approximately US¢ 5.5/kWh, which is lower than import prices. We believe it would be justified to raise the ceiling tariff to at least US¢ 6.5/kWh during winter period, especially considering the competitive nature of the market and getting MoUs.

GEMM 2015 will greatly improve the groundwork for the private sector to lead the development of the hydropower sector in Georgia by providing transmission paths, trading tools, and risk mitigation options that hydropower plants require to sell their electricity into the Turkish and regional competitive electricity markets. The MENR has committed to complete GEMM 2015 and adopt semi-annual actions plans for guidance towards GEMM 2015 implementation. The following have been identified as key steps to capitalize on attractive prices in regional power markets and good prospects for HPP projects:

- The establishment of a Market Operator (MO) and a Transmission System Operator (TSO)
- Establishment of legislative and contractual frameworks
- Harmonization with Turkey’s electricity trading platform
- Separation of generation and distribution assets from the same company

An agreement is in place to develop the Geographic Information Systems (GIS), which will consolidate hydro-meteorological data in digital form and allow users to manage water resources more effectively. The agreement between USAID, the MENR, the National Environmental Agency of Georgia (NEA), and the Norwegian Water Resources and Energy Directorate (NVE) aims to implement an operational hydrological computer system with analyses tools that will benefit all water users and will facilitate the future introduction of the EU Water Framework Directive. The end results of the project include consolidating all existing hydro-meteorological data in digital form, a run-off map covering all of Georgia, an operational nationwide hydrological model, a GIS-based model to assess Georgia’s total hydro power potential.

Appendix 1: Hypothetical HPP Financial Model Analysis

Assumptions

Debt Financing	70%	Corporate tax	15%
Equity Financing	30%	Property tax	1.0%
Equity Amount, US$	9,000,000	Tariff growth rate	3.0%
Debt Amount, US$	21,000,000	Carbon credit allowance coefficient (gr. per kWh)	0.3999
Debt Interest rate	11%	Carbon credit Price, US$	12
Debt Maturity, yrs	11	Export	80%
Cost of Equity	16%	Domestic Sales	20%
WACC	11.35%	Tariff Export, US$	0.09
Installed Capacity MW	15.00	Tariff Domestic, US$	0.04
Capacity Load	40%	Average Tariff, US$	0.07
Output kWh	65,700,000	Cost per MW, US$	2,000,000
Technical losses and own consumption	3%	SG&A cost, % of revenue	2%
O&M cost, % of revenue from electricity	3.0%	Transmission and system services, US$	0.012

Source: BoG Research

Income statement, US$

Period	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
Revenue	**0**	**0**	**4,840,040**	**4,985,241**	**5,134,799**	**5,288,843**	**5,447,508**	**5,610,933**	**5,779,261**	**5,952,639**	**6,131,218**	**6,257,836**	**6,387,107**	**6,519,086**	**6,653,832**
Chg,y/y				*3%*	*3%*	*3%*	*3%*	*3%*	*3%*	*3%*	*3%*	*2%*	*2%*	*2%*	*2%*
COGS	0	0	(1,033,537)	(1,025,609)	(1,017,803)	(1,010,124)	(1,002,573)	(995,157)	(987,878)	(980,740)	(973,749)	(979,948)	(985,625)	(976,022)	(966,491)
Gross profit	**0**	**0**	3,806,504	3,959,633	4,116,995	4,278,719	4,444,934	4,615,776	4,791,383	4,971,899	5,157,469	5,277,889	5,401,482	5,543,064	5,687,341
Gross margin			*79%*	*79%*	*80%*	*81%*	*82%*	*82%*	*83%*	*84%*	*84%*	*84%*	*85%*	*85%*	*85%*
SG&A	(92,967)	(94,865)	(96,801)	(99,705)	(102,696)	(105,777)	(108,950)	(112,219)	(115,585)	(119,053)	(122,624)	(125,157)	(127,742)	(130,382)	(133,077)
EBITDA	**(92,967)**	**(94,865)**	**3,709,703**	**3,859,928**	**4,014,299**	**4,172,942**	**4,335,984**	**4,503,558**	**4,675,798**	**4,852,846**	**5,034,845**	**5,152,732**	**5,273,739**	**5,412,682**	**5,554,264**
EBITDA margin			*77%*	*77%*	*78%*	*79%*	*80%*	*80%*	*81%*	*82%*	*82%*	*82%*	*83%*	*83%*	*83%*
D&A	0	(480,000)	(1,200,000)	(1,200,000)	(1,200,000)	(1,200,000)	(1,200,000)	(1,200,000)	(1,200,000)	(1,200,000)	(1,200,000)	(1,200,000)	(1,318,080)	(1,318,080)	(1,318,080)
EBIT	**(92,967)**	**(574,865)**	**2,509,703**	**2,659,928**	**2,814,299**	**2,972,942**	**3,135,984**	**3,303,558**	**3,475,798**	**3,652,846**	**3,834,845**	**3,952,732**	**3,955,659**	**4,094,602**	**4,236,184**
EBIT margin			*52%*	*53%*	*55%*	*56%*	*58%*	*59%*	*60%*	*61%*	*63%*	*63%*	*62%*	*63%*	*64%*
Financial expenses	(132,000)	(132,000)	(3,383,541)	(3,383,541)	(3,383,541)	(3,383,541)	(3,383,541)	(3,383,541)	(3,383,541)	(3,383,541)	(3,383,541)	(3,383,541)	(3,383,541)	0	0
PBT	**(224,967)**	**(706,865)**	**(873,838)**	**(723,613)**	**(569,242)**	**(410,599)**	**(247,557)**	**(79,984)**	**92,257**	**269,305**	**451,304**	**569,191**	**572,118**	**4,094,602**	**4,236,184**
Income tax expense	0	0	131,076	108,542	85,386	61,590	37,134	11,998	(13,839)	(40,396)	(67,696)	(85,379)	(85,818)	(614,190)	(635,428)
Net profit	**(224,967)**	**(706,865)**	**(742,763)**	**(615,071)**	**(483,855)**	**(349,009)**	**(210,423)**	**(67,986)**	**78,418**	**228,909**	**383,608**	**483,812**	**486,301**	**3,480,412**	**3,600,756**

Source: BoG Research

Project valuation

Project IRR	**13%**														
Project NPV	**$2,356,960**														
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
EBIT	(92,967)	(574,865)	2,509,703	2,659,928	2,814,299	2,972,942	3,135,984	3,303,558	3,475,798	3,652,846	3,834,845	3,952,732	3,955,659	4,094,602	4,236,184
-Tax expense	0	0	131,076	108,542	85,386	61,590	37,134	11,998	(13,839)	(40,396)	(67,696)	(85,379)	(85,818)	(614,190)	(635,428)
-Tax shield on interests	0	0	(507,531)	(507,531)	(507,531)	(507,531)	(507,531)	(507,531)	(507,531)	(507,531)	(507,531)	(507,531)	(507,531)	0	0
+D&A	0	480,000	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000	1,318,080	1,318,080	1,318,080
-Capex	(12,000,000)	(18,000,000)	0	0	0	0	0	0	0	0	0	(2,952,000)	0	0	0
-Increase in working capital	0	0	(101,001)	(183,708)	(12,240)	(12,573)	(12,915)	(13,268)	(13,632)	(14,006)	(14,392)	(8,828)	(9,066)	(10,724)	(10,913)
FCFF	(12,092,967)	(18,094,865)	3,232,247	3,277,230	3,579,914	3,714,428	3,852,671	3,994,756	4,140,796	4,290,913	4,445,226	1,598,994	4,671,324	4,787,768	4,907,924
Terminal Value	3,478,020														

Source: BoG Research

IRR sensitivity analysis

Tariff, US$	Cost per MW, US$: 1,550,000	1,700,000	1,850,000	2,000,000	2,150,000	2,300,000	2,450,000
0.05	15%	13%	12%	11%	10%	9%	8%
0.06	18%	16%	15%	14%	13%	12%	11%
0.07	21%	19%	18%	16%	15%	14%	13%
0.08	23%	21%	20%	19%	17%	16%	15%
0.09	26%	24%	22%	21%	20%	18%	17%
0.10	28%	26%	24%	23%	22%	20%	19%
0.11	30%	28%	26%	25%	23%	22%	21%

NPV sensitivity analysis

Tariff, US$	Cost per MW, US$: 1,550,000	1,700,000	1,850,000	2,000,000	2,150,000	2,300,000	2,450,000
0.05	$187,876	$77,176	-$33,524	-$144,224	-$254,924	-$365,624	-$476,324
0.06	$486,881	$376,182	$265,482	$154,782	$44,082	-$66,618	-$177,318
0.07	$785,887	$675,187	$564,487	$453,787	$343,087	$232,387	$121,687
0.08	$1,084,892	$974,192	$863,492	$752,792	$642,092	$531,392	$420,692
0.09	$1,383,898	$1,273,198	$1,162,498	$1,051,798	$941,098	$830,398	$719,698
0.10	$1,682,903	$1,572,203	$1,461,503	$1,350,803	$1,240,103	$1,129,403	$1,018,703
0.11	$1,981,909	$1,871,209	$1,760,509	$1,649,809	$1,539,109	$1,428,409	$1,317,709

Source: BoG Research

Appendix 2: New rules on HPP construction in Georgia – key steps

MENR publishes on its website a list of available potential HPP projects

↓

Expression of interest (EOI) is made online by an entity or a consortium of entities

↓

MENR selects all the applications that satisfy the basic requirements for participation

- In case of multiple parties that qualify through the expression of interest round, **the government chooses the winner by considering which one offers the lowest price to ESCO** for their 20% required supply

↓

Within 15 working days of receiving the above notification, the participants have to provide a bank guarantee in the amount of US$ 5,000 per MW of expected HPP generation capacity

↓

The winner of the expression of interest contest signs a MoU with the Government of Georgia and ESCO and potentially other third parties

- One of the key requirements for the winner will be that 10 years following the start of operations 20% of the electricity generated must be sold to ESCO at a guaranteed pre-determined price

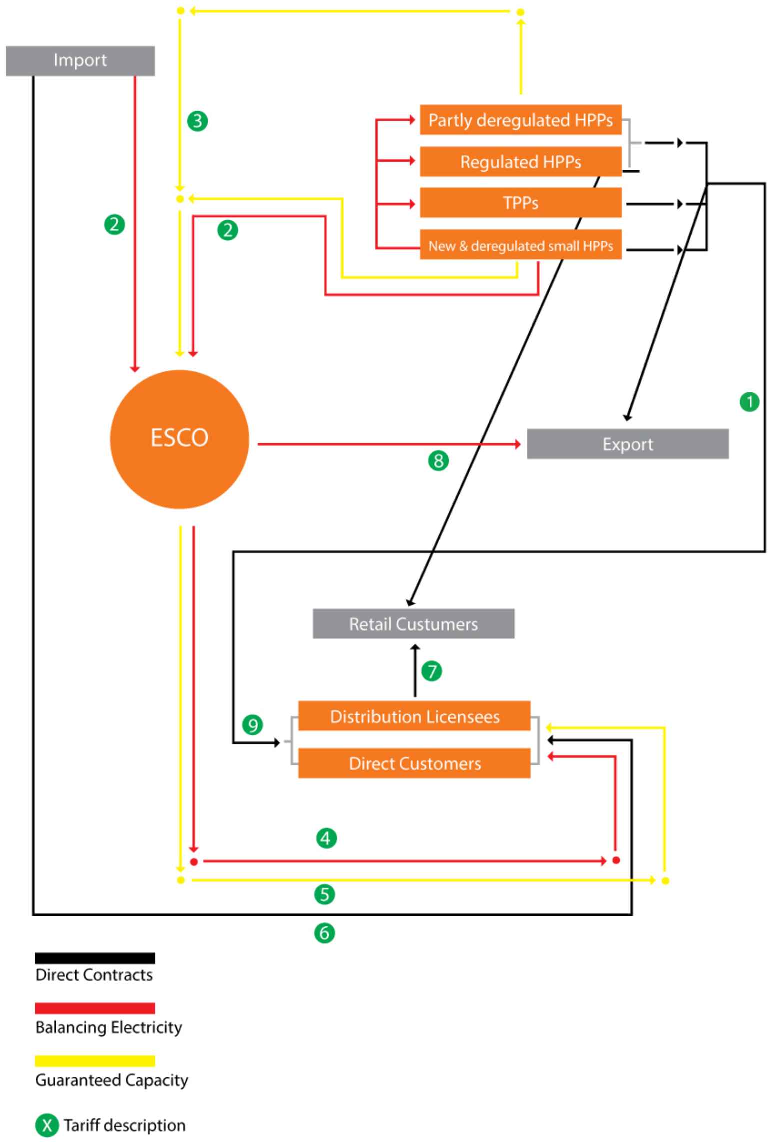
↓

The winner has to provide a construction-related bank guarantee to the Government of Georgia in the amount of US$ 100,000 per MW for HPPs under 100MW capacity and US$ 50,000 per MW for HPPs with over 100MW capacity

↓

Penalties for delays in beginning construction or starting operations as agreed in the MoU amount to 0.5% of the construction guarantee amount per day of delay; if this amount surpasses 50% of the total guarantee held the GoG has the right to cancel the agreement and retain the total amount of the construction guarantee

Appendix 3: Georgian electricity market and tariffs description



1. **Direct contract tariffs**
   a. Bilateral direct contracts are signed between eligible entities
   b. The price of the contracts depends on the status of the seller (fully regulated, partially deregulated, or fully deregulated)
   c. Direct contracts require registration by the GSE

2. **Balancing Electricity – purchasing tariff from ESCO**
   - The price ESCO pays to balancing electricity suppliers varies based on the nature of suppliers:
   - Regulated HPPs (Enguri & Vardnili): fixed tariff
   - Partly deregulated HPPs: Summer – lowest HPP tariff; Winter – cap margin of the tariff
   - Deregulated small HPPs: Summer – lowest HPP tariff; Winter – highest tariff of balancing electricity
   - TPPs: cap margin of the tariff
   - Memorandum prices for new HPPs

3. **Guaranteed Capacity – purchasing tariff from ESCO**
   a. Standby costs for guaranteeing a certain amount of supply if needed (storage, maintenance, etc.) – decided by GNEWSRC
   b. Full cost of the electricity used whenever Guaranteed Capacity is brought into the system; suppliers get compensated for the full cost of electricity (e.g. cost of gas)

4. **Balancing Electricity – selling tariff from ESCO**
   a. For the distribution licensee and direct customers, the balancing electricity tariff is the weighted average price of balancing electricity purchased by ESCO

5. **Guaranteed Capacity – charges by ESCO**
   to distribution licensees and direct customers

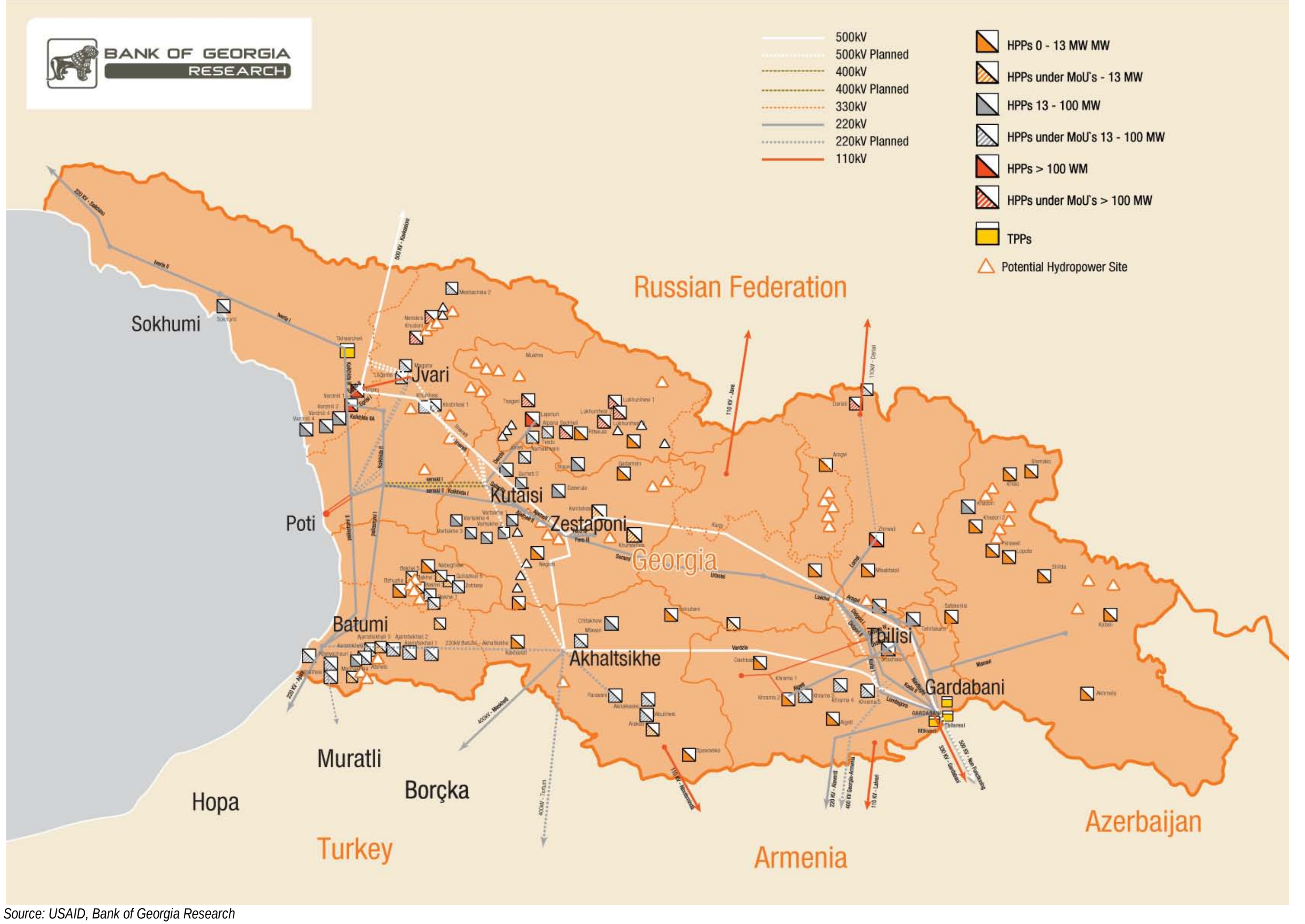
6. **Import tariffs**
   a. Imports that do not go through ESCO are similar to direct contracts, however, most importers prefer to run the imported electricity through ESCO's Balancing Electricity program to dilute the high price of imported electricity for final buyers

7. **Retail tariffs**
   a. The Commission sets a cap marginal tariff on electricity sales to retail customers

8. **Balancing Electricity** – export tariffs for the electricity that is exported
   a. The highest tariff of the balancing electricity volumes purchased by ESCO

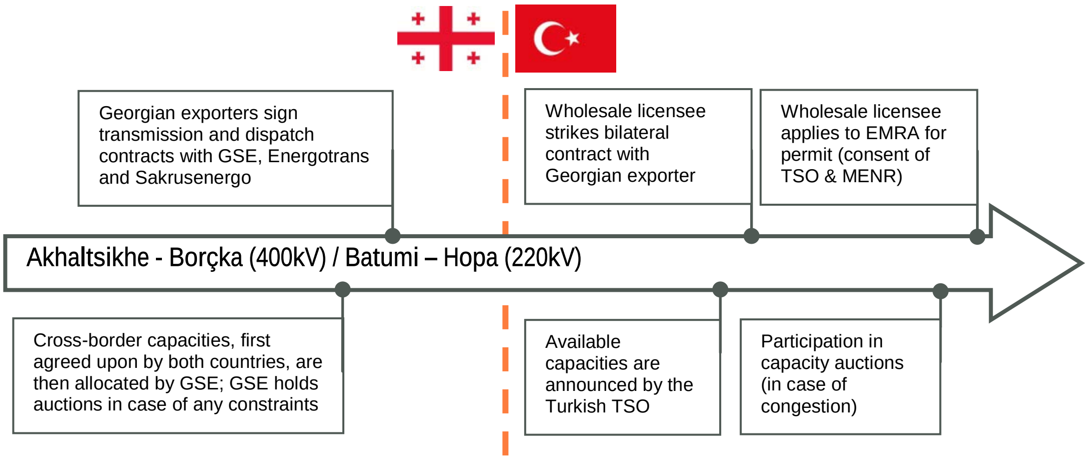
Source: ESCO, MENR, BoG Research

Appendix 4: Power plants and transmission networks map



Source: USAID, Bank of Georgia Research

Appendix 5: Exporting electricity to Turkey and Turkish tariffs



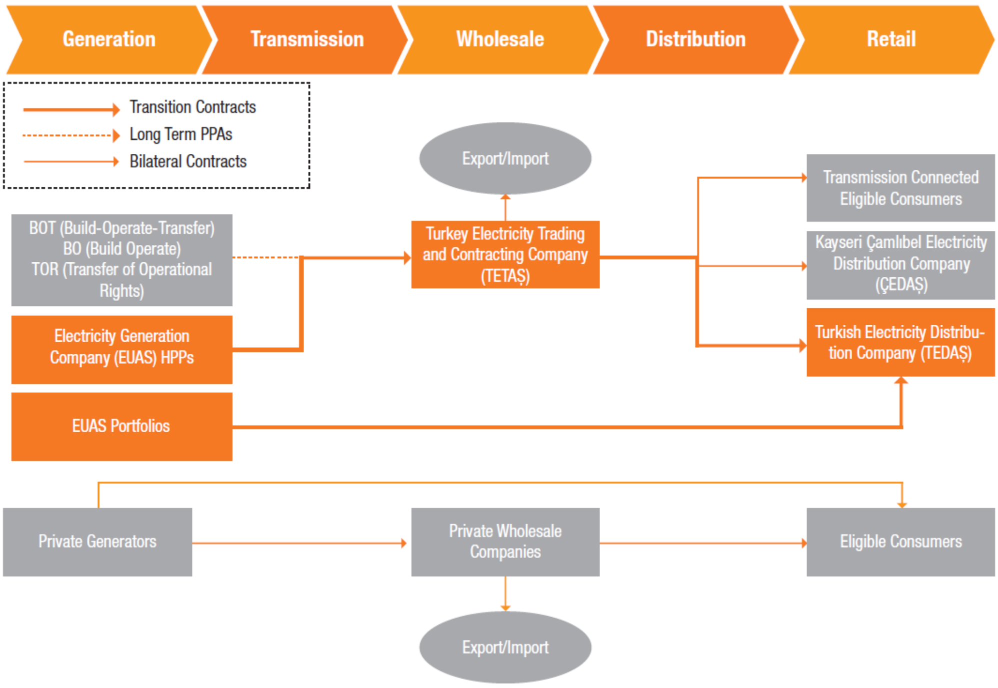
Note: TSO – Transmission Service Operator; GSE – Georgian State Electrosystem; MENR – Ministry of Energy and Natural Resources of Georgia; EMRA – Energy Market Regulatory Authority of Turkey
Source: TEIAS, ESCO, BoG Research

Monthly average wholesale tariffs are provided by TEIAS. The market model is competitive, with prices determined by supply and demand. The sale of electricity is conducted primarily through bilateral agreements.

Tariffs regulated by the EMRA are as follows:

- Connection and use of system tariffs
- Transmission tariff
- TETAS wholesale tariff
- Distribution tariffs
- Retail tariffs applicable to non-eligible consumers

Diagram 1: Electricity market participants in Turkey



Source: USAID/Deloitte; BoG Research

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