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DIAGNOSIS OF APPROVED ELECTRICITY MARKET CONCEPT DESIGN, EMCD III

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14 August 2020

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ACRONYMS

BM	Balancing Mechanism
CfD	Contract for Difference
DAM	Day Ahead Market
DSO	Distribution System Operator
EMCD	Electricity Market Concept Design
EPG	Energo-Pro Georgia
ESCO	Electricity Market Operator
EU	European Union
GNERC	Georgian National Energy and Water Supply Regulatory Commission
GoG	Government of Georgia
GSE	Georgian State Electrosystem
GSP	Grid Supply Point
GWh	Gigawatt Hour
HPP	Hydro Power Plant
HVDC	High Voltage Direct Current
IDM	Intraday Market
kV	Kilovolt
MoU	Memorandum of Understanding
MW	Megawatt
MWh	Megawatt Hour
NDM	Non-Daily Metering
OTC	Over the Counter
PPA	Power Purchase Agreement
PSO	Public Service Obligation
RES	Renewable Energy Sources
SLR	Supplier of Last Resort
Telasi	Electricity Distribution Company of Tbilisi
TPP	Thermal Power Plant
TSO	Transmission System Operator
TWh	Terawatt Hour
USAID	United States Agency for International Development
USS	Universal Service Supplier
VRE	Variable Renewable Energy
WPSO	Wholesale Public Service Organisation

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1. INTRODUCTION

The Government of Georgia (GoG) has developed an Electricity Market Conceptual Design (EMCD) which identifies the roles and responsibilities required to manage the component parts of the electricity market and the transitional steps up to 2026 at which time all electricity consumers in Georgia will be able to choose their electricity supplier.

However, the difficulties in storing electricity to any significant level coupled with the requirement match supply and demand instant by instant requires a more complex market mechanisms than with other commodities. The introduction of a new and very different electricity trading mechanism is challenging, both in terms of the technologies required to support the necessary systems and processes, and the people in the market who will be operating and trading in the new environment.

Georgia faces several specific issues which have to be addressed during the implementation of the EMCD including:

- Georgia is a relatively small market; it will be challenging to generate sufficient market liquidity to ensure representative pricing;
- Because of the high proportion of Hydro Power Plants (HPP) in the generation mix, Georgia has surpluses of low cost hydro surpluses in the summer and a high reliance on thermal generation and imports in the winter – pricing will be highly seasonal;
- With the exception of Turkey via the High Voltage Direct Current (HVDC) link, it is not currently possible to be simultaneously connected to the neighbouring countries, thus limiting opportunities for regional electricity exchange;
- There is a significant drain on electricity resources in the supply to Abkhazia, which is outside of the electricity market control, but which nevertheless must be catered for;
- The are many long term Guaranteed Capacity contracts, Power Purchase Agreements (PPA) and other contractual arrangements which are incompatible with a liberalized bilateral energy market and which also must be accommodated in the design.

Once fully implemented, the market will have all of the tools to enable the optimization of resources throughout the day, month and year:

- A Balancing Market (BM) to provide a tool for the electricity Transmission System Operator (TSO) to procure electricity to manage differences between contracted and actual consumption;
- A mechanism for the TSO to contract for ancillary services on a competitive basis;
- A Day Ahead Market (DAM) to enable participants to modify their bilateral positions to avoid BM risk;
- Intraday Market (IDM) to further adjust positions ahead of Gate Closure;
- Direct bilateral Over the Counter (OTC) contracts;
- Forwards market(s) to enable trade in standardised contracts for procurement and risk management.

2. BACKGROUND

Generation, transmission and distribution (which includes supply to the end user) functions have been legally unbundled in Georgia for some years. The current market model in Georgia provides for generation following[1] bilateral contracts between generators and distribution companies, many of which are between distribution companies and the power plants that they own or manage; and a small number of large consumers of electricity (5 at the time of writing) designated as Direct Customers who have contracts with specific HPPs. With the exception of small HPP plants (less than 13 MW), generation prices are capped for privately owned generators, and are fully regulated for the state owned Enguri / Vardnili cascade which supplies around 30% of total system generation in a year with average precipitation.

Electricity Generation in Georgia is provided by a mix of hydropower plants and natural gas thermal generation. There is an operating wind farm providing power to the grid and plans for further Variable Renewable Energy (VRE) investment, and a recently constructed coal burning plant. Current installed generation capacity totals 4,050 MW[2] in 2017 and in 2019 total generation was approximately[3] 11.8 TWh, total consumption was 12.8 TWh.

In 2019, the generation mix was made up as follows:

HPP	-	67%
TPP	-	21%
Imports	-	12%

Total supply was 13.3 TWh.

The transmission system operator is the Georgian State Electrosystem (GSE), a Joint Stock Company100% owned by the state through the Partnership Fund. It owns the Transmission lines with voltages below 400 kV, the 400 kV and 500 kV lines are owned by Energotrans which is a subsidiary of GSE, and by Sakrusenergo, a company jointly owned by the State of Georgia and Russian state owned JSC Federal Network Company of the Unified Energy System. GSE is the only dispatch licensee.

The transmission network in Georgia consists of 500 kV, 330 kV, 220 kV, 110 kV and 35 kV voltage lines. A 500 kV transmission line through the Caucasus Mountains and 220 kV through Abkhazia connects Russia to the Georgian grid. There is are 500 kV and a 330 kV connections with Azerbaijan, and with Armenia and Turkey at 220 kV. There are also isolated 110 kV connections with Armenia and Russia. There are plans to upgrade the connections with Russia via a 500 kV connection through the Dariali gorge.

A 500/400 kV HVDC connection to Turkey with a capacity of approximately 700MW was commissioned in 2013. Deregulated small, recently constructed HPP (Renewable Energy Sources (RES)) has priority access to the line; spare capacity is sold through an explicit auction managed by GSE.

There are two privately owned distribution companies in Georgia, Telasi and Energo-Pro Georgia (EPG). Network operations and supply are integrated.

There are five energy intensive users taking electricity directly from the transmission network based on bilateral contracts with generators. Three of the five joined the market in 2018.

Electricity Market Operator (ESCO) has the responsibilities in the current market to manage payments falling due for wholesale electricity supply that is not subject direct contracts in the current market and arrange import/export contracts and is a party to several PPA. ESCO also settles the reserve energy provided by the thermal plants in the winter season.

- There are several new HPP stations with PPAs that provide for guaranteed sales to ESCO for various periods during the year, and several governmental Memorandum of Understanding (MoUs) for new developments that will result in new PPAs;

[1] Generation following meaning all output of the generator is taken by the supplier at the negotiated price. There is no particular volume of energy
[2] Source: GSE Annual Report 2017
Source: GSE http://www.gse.com.ge/sw/static/file/GSE_ANNUAL_REPORT_2017_ENG_FOR_WEB.pdf
[3] Source: ESCO https://esco.ge/en/energobalansi/by-year-1/2018-energy-balance e

- All Thermal Power Plants (TPPs) have guaranteed available capacity payments which are settled through ESCO but with Direct Contracts with distribution companies under regulated tariffs for the energy component of their invoice;
- There are some arrangements that permit post-2008 small HPPs which have unrestricted priority access to the HVDC interconnector to Turkey.

Although participants are not prevented from directly importing electricity, in practice imports are managed by ESCO. The bulk of the commercial arrangements are through direct contracts between the Distribution System Operators (DSOs) and eligible customers; ESCO sells around 15% of the annual total consumption.

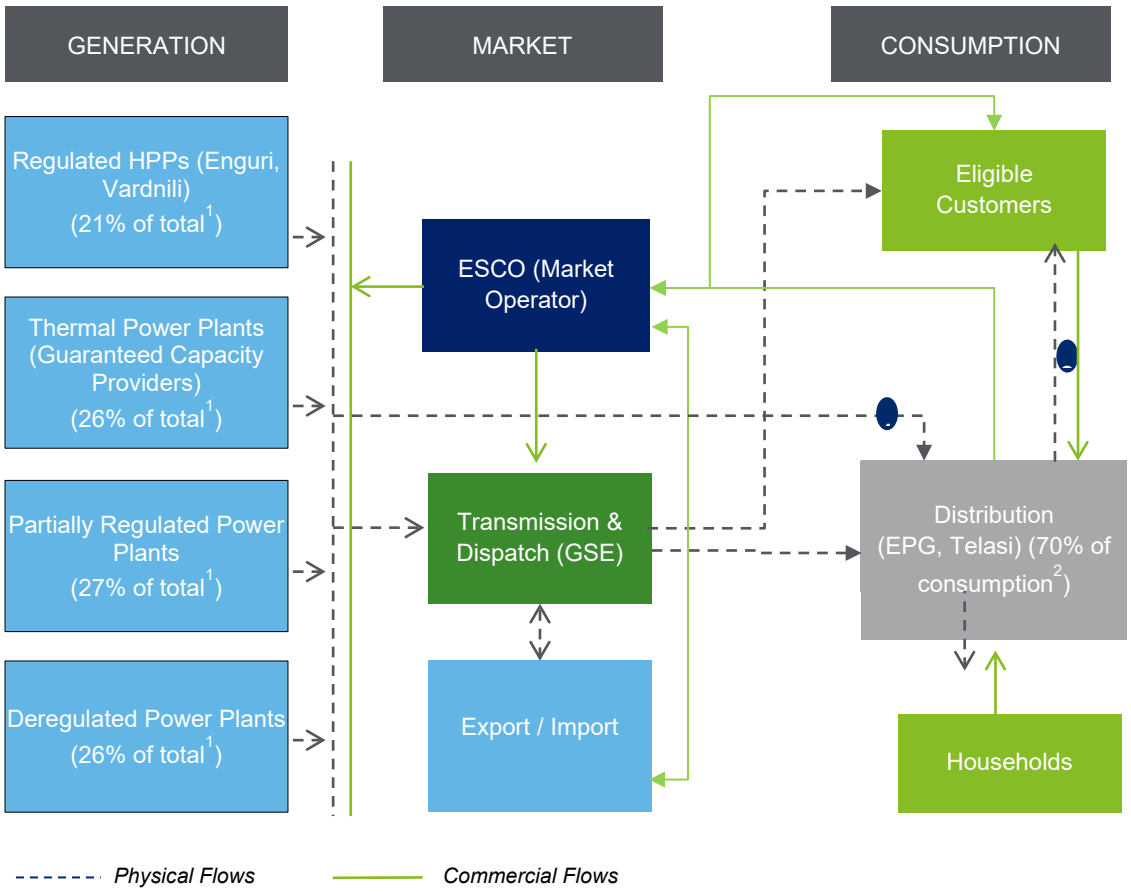
The bulk of electricity imports came from Azerbaijan in 2018, with some supply from Russia and a little from Armenia.

Regarding exports[4], Turkey was the main market following the commissioning of a 700 MW HVDC link that went into service in 2013. Any generator is permitted to export to Turkey, but as part of an incentive to investors, recent (post-2008) small HPPs have priority access to transmission capacity. However, because of a decrease in prices on the Turkish side of the interconnector, the line is currently under-utilized. In 2018, 383 GWh were exported to Turkey spread over May, June and July. Small volumes were exported to Russia, Azerbaijan and Armenia.

The bilateral contracts exist between distribution companies and generators or 'Direct Customers' (those connected at 35 kV) and generators and are generally for a volume of electricity to be delivered over and agreed time, perhaps weeks or months in duration. They are not firm and are not hourly profiled, so they are not helpful in dispatch planning. There is no process for physical notification of supply.

The figure below shows the current relationships schematically:

Figure 1: Current Structure



[4] https://esco.ge/en/energobalansi

In the figure above, the green arrows designate Direct (bilateral) Contracts, the black dashed arrows designate energy flows.

The Direct Contracts specify a price, a delivery period and a tolerance on delivery, for example, a contract may be for 50 GWh +/- 20% for delivery between 1st June and 31st August. The contracts are not profiled and not firm, and there is no obligation to notify the TSO of intended delivery for any particular hour. GSE dispatches according to recognized operational practice, taking account of demand, reservoir levels, state of TPP plants, import contracts etc.

At the end of each settlement period, ESCO calculates the flows between the contracted parties and notifies them of their payment obligations. Any electricity which has been dispatched outside of contract tolerance is deemed ex-post as balancing electricity and is settled by ESCO.

Most of the wholesale electricity generation is sold to distribution companies and large industrial consumers through bilateral contracts at fixed or capped regulated tariffs. The remainder is defined as balancing energy, managed by ESCO and priced depending on the generation mix used to supply the electricity. The balancing electricity covers the difference between contracted and consumed electricity and is priced at the average weighted price from the tariffs.

3. MARKET DESIGN CONCEPT

The EMCD consists of 4 Chapters containing 19 Articles and an annex which specifies the stages of market implementation. Chapter 1 describes the principles of the market, Chapter 2 defines the segments and functions, the third Chapter specifies the obligations of the actors in the market, and Chapter 4 outlines the transitional provisions. The appendix outlines the timetable for the phases of implementation:

The 3 stages of market implementation progressively re-organizes the existing structure into a hybrid pool / bilateral form to allow for the co-existence of the deregulated and regulated sectors during the transition. *The timetable for Stage 4, the roll out to all consumers, is not mentioned in the Electricity Market Design Concept, but it presumably entail the deregulation of all generation, the ability for residential and small businesses to choose their supplier, and the enactment of laws protecting customers from malpractice from suppliers*.

3.1 STAGES OF MARKET OPENING

CURRENT OPERATING REGIME UNTIL 30TH JUNE 2021

- In the current regime, large customers connected at 35 kV and above with an (average?) consumption in excess of 4 GWh per month have the option to enter direct bilateral agreements with generation plant excluding those subject to Power Purchase Agreements or Guaranteed Capacity payments. The contracts are assumed[5] to be load following in that the buyer pays for all of the output of a contracted producer at a negotiated price (which is capped by the Regulator for pre 2008 generation). Uncontracted production is purchased by ESCO according at the regulated tariff and the blended output charged out to the distribution companies and to direct customers who consumed more in a month than the sum of their contracts.
- the TSO dispatches generation according to least cost principles.
- 2.8 TWh in 2019.

FROM 1ST JULY 2021

- Consumers connected at 6 kV and above consuming more than 1 GWh per month are required to purchase electricity bi-laterally from de regulated (i.e. without a Public Service Obligation (PSO)).
- Day Ahead, Balancing and Forwards Market introduced.
- Estimated 3.7 TWh.

FROM JULY 2022 UNTIL 2026

- all customers except household and small business enter the market. No estimate given at this stage; assume 50% of total supply; approx. 6.5 TWh
- Consumers connected at 6 kV and above enter the market. Intraday market introduced.
- Total of 4.3 TWh.

FROM 2026

- Not explicit. Presumably, market opens to all consumers.

3.2 MARKET SEGMENTS

The EMCD specifies two distinct segments prior to the transition to full competition, consisting of the competitive sector encompassing and the regulated sector containing the captive consumers and the centrally dispatched generation fleet at tariffs specified by Georgian National Energy and Water Supply Regulatory Commission (GNERC).

[5] Since there is no mechanism to establish volumes of electricity supplied for multiple buyers, there is no method to allocate supply to more than one consumer. This method only works where the total supply of contracted electricity is less than the total consumption of buyer, with the difference between contracted and actual consumption procured from e ESCO at the balancing price.

The competitive sector includes:

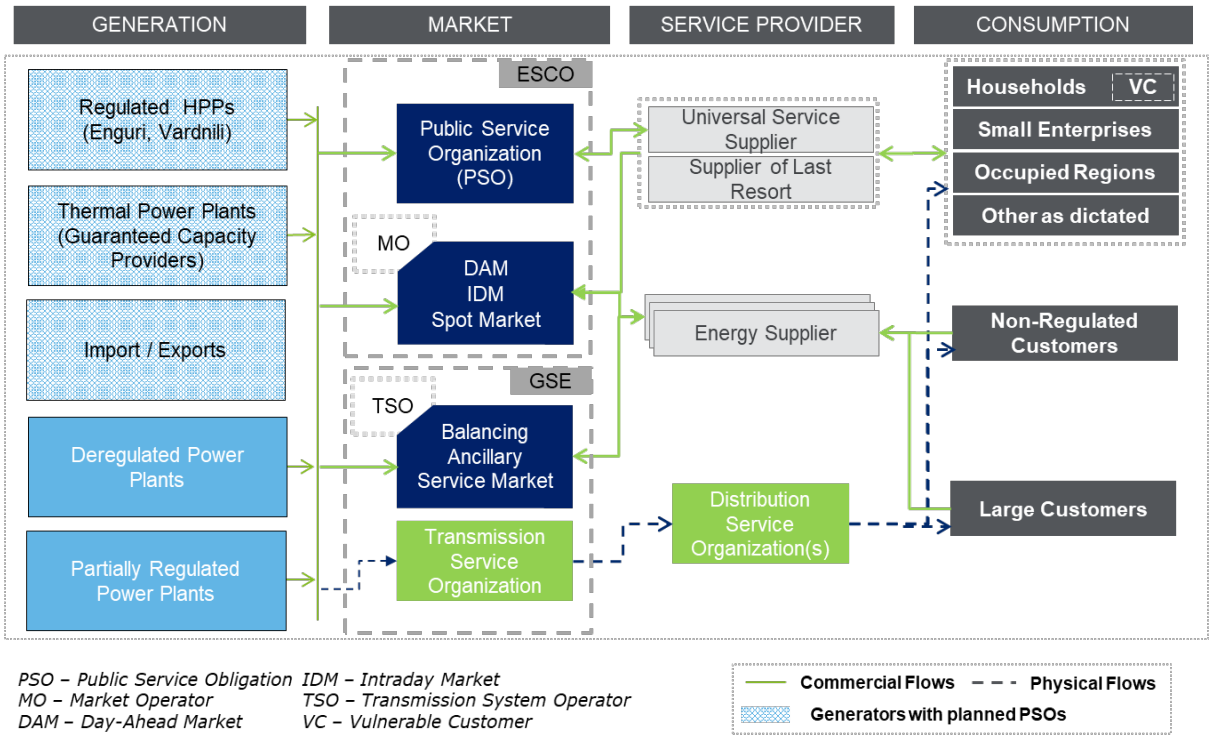
- a DAM;
- an IDM;
- a Bilateral Contracts Market (effectively a Forwards market);
- a Balancing market;
- deregulated (i.e. not subject to regulated tariffs or central dispatch) generation;
- suppliers (purchase from the competitive market and resell to eligible customers);
- eligible customers (contracting directly through contracts or procuring through suppliers) The DAM, IDM and Bilateral markets will be organised by the new Market Operator.

The regulated sector includes:

- a Wholesale Public Service Organisation (WPSO), responsible for purchasing all regulated generation and imports;
- Universal Service Supplier(s) (USS) who will be regionally based and will purchase electricity from the WPSO and re-sell it to all consumers in the regulated segment at regulated tariff; and may purchase from the competitive market if there is insufficient supply from the WPSO;
- the regulated Generation fleet, designated as 'Electric Generator proving a Public Service';
- DAM;
- IDM;
- Bilateral Contracts Market;
- Balancing Market.

A draft implementation schedule is included in the Design Concept which identifies the progressive roll out of eligible consumers of electricity, reproduced below:

Figure 2: Revised Market Design



The schematic above represents the transactions and interactions in the penultimate incarnation of the electricity market.

3.3 DESIGN PRINCIPLES

The objectives are achieved through a phased implementation strategy comprising of stages.

STAGE 1 FROM 2021

- The market opens to a selection of commercial consumers, mandating that organizations connected to 6/10 kV and 11/35 kV consuming more than 1 GWh per annum leaves the regulated sector; 4.3 TWh (35% of consumption)
- The Day Ahead, Balancing and Forwards markets open. Most of the large consumers have been buying electricity directly from generation companies for many years, but this first incarnation requires them to contract by the hour and accept imbalance costs. Similarly, the deregulated generation companies must also notify the TSO of their hourly dispatch schedule and accept imbalance charging in the event of deviation from the reported schedule. To facilitate this, selected generation must be made available exclusively to the market sector, and a balancing market established to provide a mechanism for participants to procure balancing electricity and to establish a price for that electricity.
- Approximately 3.7 TWh or around 30% of consumption will be taken out of the regulated market.

STAGE 2 FROM 2022

- The Intraday market is opened at the stage.
- The market opens to all but residential/small commercial sector. Approximately 6.5 TWh, approx. 50% of consumption

4. ANALYSIS

4.1 MAINTAINING PRICES IN THE REGULATED MARKET

The EMCD requires that the in the first two release the tariffs paid by consumers and received by producers is not affected by the implementation of the market. This is achieved by Article 10 which requires that, that the WPSO ensures that prices paid to producers reflect the price of PPA arrangements, Guaranteed Capacity Payments for the TPPs, Contract for Difference (CfDs) for renewables, tariffs fixed by GNERC for producers, supply to Abkhazia, and to Universal Service Suppliers regardless of the DAM prices by compensating or being compensated by the WPSO for the difference. Articles 11 and 12 require that the participants trade directly tin the market mechanisms, or that the WPSO resells their output into the organised markets.

Noting that a different price will be established for every hour of the day on the Day Ahead market, the balancing mechanism and latterly on the Intraday market, the effort to calculate the variance between the sum of the prices and the tariffs will require significant administrative effort on behalf of the WPSO. This will be exacerbated in the second release of the market, when Non-Daily Metering (NDM) for qualified retail consumers is involved.

4.2 MARKET LIQUIDITY

Georgia is a small market, and there is little opportunity in the short to medium term of coupling with any of the international neighbours at this stage, except possibly through Turkey.

If a marketplace has a high volume of trade, then the ask price (offer to sell) should be close to the bid price (offer to buy) – stocks should be easy to sell and resell.

There are some barriers to trading that may adversely affect trading in electricity in Georgia:

- Georgia has around 1.7 million households and with an annual consumption of 12.5 TWh in 2018, which is a small market;
- It has little or no access to neighbouring liquid markets – transactions are generally negotiated bi-laterally;
- There is no history of electricity trading in the Georgian generation or supply companies – the focus of such companies is traditionally asset management;
- There is no familiarity with the products in the market – winter peakload, summer baseload etc.

Therefore, liquidity may well be a problem given the size of the market, and in the short term, the experience of the market members.

To promote liquidity, the EMCD has the following clauses:

- Article 11 requires that generation companies supported by PPA should be offered by the PPA holder to the organised market or bought by the WPSO and then offered to the organised market by the WPSO. The WPSO ensures that the producer are paid under the terms of the PPA via a contract for difference. This also applies to RES who benefit from guaranteed prices through a CfDs with the WPSO.
- Article 12 requires that producers subject to a PSO offer their electricity to the market with their price guaranteed by a CfD through the WPSO. The Article provides for the same mechanism for the TPPs who benefit from the Guaranteed Capacity agreement – the WPSO will offer the production to the market.
- Articles 14 regarding procurement for the Universal Service Suppliers and from the WPSO for Abkhazia supply both require that they buy all of their supply from the DAM and Intraday markets.

The effect of clauses 11 & 12 will be to concentrate liquidity in the short term markets. However, there is little incentive for realistic bids and offers from the regulated producers since the risk is absorbed by the WPSO leading to unrepresentative prices in the markets. It is likely that participants in the competitive market will seek to establish direct bilateral contracts with those producers not designated as PSOs, with residual trading on the short term markets.

Articles 14 means that a large percentage of supply will be trades through the short term markets, which will leave little room for a forward market – which is where the liquidity is generated in most

electricity markets with each MWh being traded several times before delivery, and where risk management tools are available. The constraint should be relaxed as soon as possible.

4.3 DAY AHEAD VOLATILITY

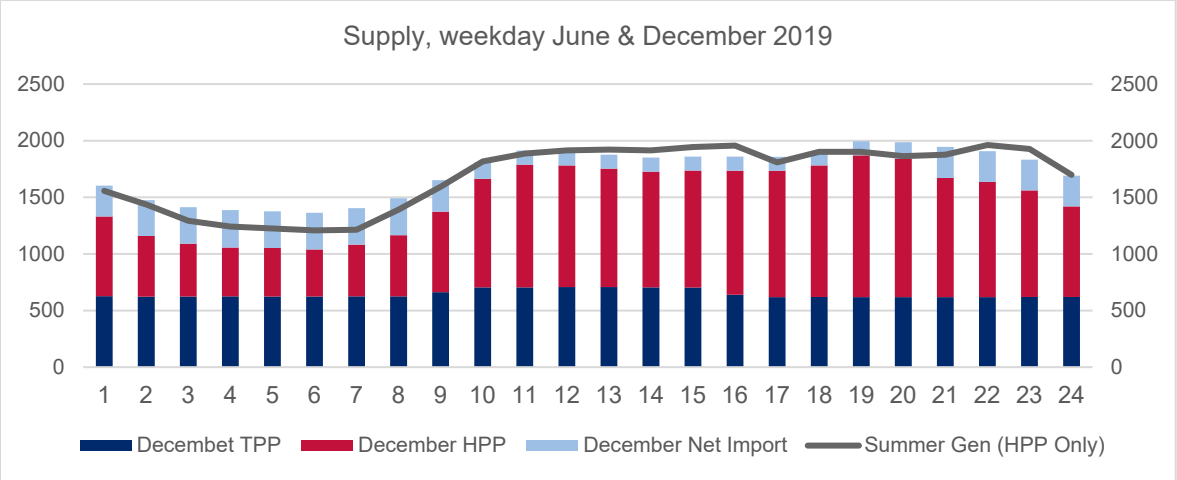
Although the market rules are not yet available, the DAM will probably open in the morning of the day before delivery; the DAM will close (Gate Closure), at a time before the Intraday commences and runs for an hour or two before the BM commences.

The DAM is a closed auction which seeks to maximise social welfare in each interval, 1 hour in the case of Georgia. To establish the price in each hour, producers offer to sell a given volume of electricity at a price not less the offer price (supply) and consumers bid to buy at a price not greater than the bid price (consumption). An algorithm then establishes the equilibrium price at which supply matches demand. Sellers who offer prices at or below the equilibrium price are paid the equilibrium price, and buyers who have bid at or above the equilibrium price pay the equilibrium price.

In mature markets, the DAM represents a small part of the traded electricity – it is typically no more than 10% of trades – and the rest of the agreements are arranged bilaterally, either direct or via the forwards markets. The participants use the DAM and Intraday to adjust their positions to avoid risk in the Balancing Mechanism.

Prices will be highly susceptible to the dispatch of Thermal Generation and Imports. TPP will tend to run 24x7 during the winter period when water reserves are low, therefore the all the HPP in the generation mix will receive the DAM strike price based on the cost of thermal generation for every hour. Conversely, in the flood prices will sink almost to zero unless a wider export market can be established.

Figure 3: Summer and Winter Supply Profile



Source: http://www.gse.com.ge/for-customers/data-from-the-power-system/production-and-consumption

The profile of an average day is not very different from summer and winter, but the winter DAM price will be set by the greater of the cost of TPP generation and Imports. Since the DAM accounts for most of the trading, USS will be purchasing all of their winter power at TPP / Import prices.

4.4 ABKHAZIA

As with USS, the WPSO procures electricity from the DAM / IDM markets to supply Abkhazia with electricity. In this role, the WPSO emulates the function of the USS, so the cost to the WPSO will be at the TPP prices in the summer.

This may increase the overall electricity cost because of the size if the Abkhazia portfolio being reimbursed at the peak summer DAM price. This would be a windfall benefit to de-regulated generators who will not be required to pay back the difference via a CfD arrangement with the WPSO.

4.5 SCHEDULING

The producers in an electricity energy market usually 'self dispatch' their generation based upon the contracts they have established directly or through commitments made on the organised markets. The generators will normally update the TSO during the course of the day ahead and intraday trading, but at gate closure they must inform the TSO of their intended injections and extractions at each meter point.

Before the commencement of the BM, all wholesale participants must provide a Final Physical Notification of which generating units will be dispatched at what output, and each off-taker what they expect to draw at each meter point. This provides the TSO the balance – long market if there is more generation than supply, short market if more supply than generation thus providing the basis for the Balancing Market.

Article 12, paragraph 1 of the EMCD requires that the TPPs will offer the energy to the DAM market, and the WPSO will manage the variance between the DAM price for the respective hour and the sum of the Guaranteed Capacity Payment and the dispatch costs of the TPP as set by the regulator. This assumes that the Guaranteed Capacity Supplier offers a price low enough to clear the market and hence to be dispatched – at zero cost to be certain, which will set the DAM at unrealistic HPP prices. It is also not clear how the GC is incorporated in market costs when the TPP is offline but still in receipt of Guaranteed Capacity payments.

4.6 BALANCING IN A 'MIXED' MARKET

The EMCD implies two different trading schemes in which the PSO generating units and the USS retail supply units have their prices guaranteed at tariff levels through the CfD approach. However, in the competitive sector the de-regulated supply and consumption must adhere to the prices established in the DAM, Intraday and balancing markets.

Noting the potential for volatility in the short term markets and balancing mechanism, It may be prudent to offer some protection for de-regulated participants from chaotic pricing by imposing some caps and collars on the short term markets. For example, in the European Union (EU) there is a recommended cap on the BM of $2000 / MWh.

4.7 ACCESS TO COMMERCIAL CONSUMERS

According to the schedule in Annex 1 of Government resolution on approval of the concept of electricity market model, commercial customers enter the market, for market opening, from July 1st, 2022. There is little in the current version of the EMCD to manage the transition from wholesale trading to prepare for the introduction of retail competition. However, Article 4 'Wholesale Market Subjects' mentions the actors: Electricity Market Operator, Transmission System Operator, Distribution System Operator, Electricity Producer (including import), Trader, Supplier, Large Consumer, Wholesale Public Service Organisation. Of these, the transition to a retail market has a significant impact on distribution operations.

DISTRIBUTION REORGANISATION

The Distribution enterprises have 3 main elements to their business:

- Distribution network management;
- Consumer relations;
- Consumption metering;

To enable competition to grow, new organisations that purchase wholesale electricity from producers, directly or through organised markets, with the intention of selling electricity to end consumers. Very briefly, this must be facilitated through

- Unbundling retail supply from the network management to ensure unrestricted access for new entrants to the retail market;
- Maintain a registry of all meters in the commercial sectors to enable a record of which supplier is serving each customer meter;
- Provide a mechanism allowing a new supplier to take over a customer from a given date, which will include recording meter readings on the day that supply switches;

- Provide a mechanism to arbitrates conflicts in supply ownership (examples are a customer agreeing contracts with more than one supplier, contractual disputes between suppliers etc.);
- Provide a meter reading service for suppliers (may be independent, but not usually on day 1);
- Act upon supplier requests in the event of customer default.

When the household market opens in 2026, further customer protection legislation will need to be drafted to ensure that unfair contracts and selling practices are avoided.

BALANCING IN THE RETAIL MARKET

As the market opens to smaller customers, many of the meters will not be hourly meters at the boundaries of the transmission system. There will be no record of the hourly consumption, which is the proposed unit for balancing.

To address this issue, it will be necessary to define a series of classes of customers who have a similar profile of consumption. Some research will be necessary to identify the divisions between the classes, but typically they will represent different types of industrial and commercial enterprise, educational establishments etc., and one or two classifications of household customer. For example:

- Households unrestricted;
- Commerce unrestricted;
- Commerce with a load factor between 20% and 30%;
- Commerce with a load factor between 30% and 40%;
- Commerce with a load factor greater than 40%.

Each of these classes are assigned a load profile which typifies their consumption pattern. Then, by knowing the total consumption for each class on a Grid Supply Point (GSP) from the Suppliers records, the load profile for each class is applied to establish the hourly load for each Supplier connected to the GSP. For each Supplier, the load from their interval metered customers for each GSP is added and the final hourly load is calculated.

The meters themselves will allocated to a grid supply point to which the distribution feeders are connected. The contracted amounts are compared with the actuals and imbalances calculated.

4.8 SUPPLIER OF LAST RESORT

Article 15 defines the role of the ‘Supplier of Last Resort’ (SLR), which is intended to prevent households losing their electricity supply because of a commercial failure of their supplier. The role of SLR is to step in and take control of the supply to consumers may otherwise be disconnected.

The Article implies that the SLR is an organisation set up to provide this protection, but it is usually a duty imposed on a particular supplier depending on circumstance to maintain supply for the short term for the residential customer at a rate reflective of average tariffs in the competitive market. It is possible – even likely - that the consumer may make no effort to change supplier in the short term.

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