”Expertise Review and analysis of the Internal Electricity Market Models” (AHEF GE80)

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<td>Prepared by</td>
<td></td>
</tr>
<tr>
<td>John Swinscoe</td>
<td>30/01/2015</td>
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<tr>
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<td>18/03/2015</td>
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<tr>
<td>Checked by</td>
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<tr>
<td>Nikos Tsakalidis</td>
<td>10/04/2015</td>
</tr>
<tr>
<td>Approved by</td>
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Definitions

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<th>Public Supply Business</th>
<th>Supplier of electricity to all non-eligible customers in their geographic area</th>
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<td>Eligible Customer</td>
<td>Customer able to choose any supplier except the public supplier</td>
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<tr>
<td>Independent Supply Business</td>
<td>Supplier able to procure electricity from generation or import sources and resell to eligible customers including export markets</td>
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<td>Direct Customer</td>
<td>Customer connect to the HV Transmission System</td>
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<td>Distribution Company</td>
<td>Current organisations which combine the functions of a DNO and supplier</td>
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<td>Grid Supply Point</td>
<td>Interface between the transmission network and a distribution network or direct customer.</td>
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<td>Non-Eligible Customer</td>
<td>Customer subject to regulated tariffs receiving supply from Public Suppliers</td>
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<td>Balancing Electricity</td>
<td>Electricity used to fill the gaps between actual and contracted consumption</td>
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<td>Regulated Pool</td>
<td>The Generators that are dedicated to the supply of non-eligible customers</td>
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<td>Regulated Pool Price</td>
<td>The average weighted tariff of the generation supplied to the non-eligible customers, including the price of any balancing electricity</td>
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### Abbreviations

<table>
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<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tr>
<td>DAM</td>
<td>Day Ahead Market</td>
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<td>BM</td>
<td>Balancing Market</td>
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<tr>
<td>EU</td>
<td>European Union</td>
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<tr>
<td>HV</td>
<td>High Voltage (6 (10)kV or 35kV)</td>
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<tr>
<td>kVA</td>
<td>Kilo-Volt Ampere</td>
</tr>
<tr>
<td>kVArh</td>
<td>Kilo-Volt Ampere Reactive hours</td>
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<tr>
<td>kW</td>
<td>Kilo-Watt</td>
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<tr>
<td>kWh</td>
<td>Kilo-Watt hours</td>
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<tr>
<td>LV</td>
<td>Low Voltage (415V)</td>
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<td>PSB</td>
<td>Public Supply Business</td>
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<td>ISB</td>
<td>Independent Supply Business</td>
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<td>DNO</td>
<td>Distribution Network Operator</td>
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<td>GSP</td>
<td>Grid Supply Point</td>
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<tr>
<td>MW</td>
<td>Mega-Watt</td>
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<tr>
<td>MWh</td>
<td>Mega-Watt hours</td>
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<tr>
<td>HVDC</td>
<td>High Voltage Direct Current</td>
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<tr>
<td>HPP</td>
<td>Hydro Power Plant</td>
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<td>TPP</td>
<td>Thermal Power Plant</td>
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<tr>
<td>OCGT</td>
<td>Open Cycle Gas Turbine</td>
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<tr>
<td>CCGT</td>
<td>Combined Cycle Gas Turbine</td>
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<tr>
<td>BSP</td>
<td>Balancing Settlement Price</td>
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<tr>
<td>ESCO</td>
<td>Electricity System Commercial Operator</td>
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<td>GSE</td>
<td>Georgian State Electrosystem</td>
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Executive Summary

This report has been prepared by ITS on the AHEF request for assistance submitted by ESCO (Electricity System Commercial Operator) ”Expertise Review and analysis of the Internal Electricity Market Models” (AHEF 80GE)

The specific objectives of the assistance were:

• To assist and advise on the development of the market model
• To assist with the definition of the roles and responsibilities of the market operator in the various phases of market evolution, and their interfaces with other organisations, including:
  o Transmission System Operator,
  o Relationships with the regulator in terms of market reporting and monitoring;
  o internal electricity traders,
  o importers and exports of electricity;
• To assist in the review of outputs from other working groups to ensure compatibility with the market model and the directives of the third package; and
• To transfer of knowledge regarding the experience of other countries in the development of statute and mechanisms for transition to a market model.

Background

Georgia has many advantages in the electricity sector, and many challenges. The advantages include, \textit{inter alia},

• A very high proportion of electricity is produce by hydro generation (75% - 85% depending on precipitation)
• relatively strong (and growing) interconnections with neighbouring states, as a proportion of domestic consumption
• well positioned geographically, with significant opportunities to become a trading hub
• the electricity industry has demonstrated a robust recovery since the difficult days of the 1990s and to the first decade of the 21st century, which were plagued by low collection rates and unreliable supply
• very large unexploited hydro potential
• political will to implement further reforms and expand competition in the sector

However there are some challenges and risks:

• the Enguri and Vardnily cascade, which produces 40%+ of Georgia’s electricity, lies on the border of Abkhazia, which is a contested territory
• there are significant winter (and occasionally summer) deficits of hydroelectricity which have to be filled by expensive imports or thermal supplies
• It is difficult to attract foreign investment to the sector because of regulatory uncertainties and low internal tariff, resulting in high risk and low returns
In 2006, Georgia ratified the “Main Directions of State Policy in the Power Sector of Georgia” which may be summarised as follows:

- replace thermal generation by developing renewable energy sources;
- To expand cross-border power trading regime with neighbouring countries
- To rehabilitate existing and construct new infrastructure for electricity transmission and natural gas transportation;
- To attract foreign investment in the energy sector in order to develop energy infrastructure of the country;
- To ensure energy security of the country through diversification of energy sources and supply routes;
- To develop east-west and north-south energy transportation infrastructure in order to increase transit capacity of the country.

Currently, a full energy sector strategy is being developed by the Ministry of Energy, and the first draft is expected towards the end of 2015. In the meantime, Georgia has applied for membership of the Energy Community (EnC), which implies that changes are required to accommodate the provisions of the Third Energy Package (TEP). The TEP has many provisions, including Regulation 714-2009 regarding Cross Border Trade, Directive 2009-72 regarding the internal market for electricity and Directive 2005-89 regarding the security of electricity supply.

The Georgian Energy Market Model 2015 (GEMM2015) strategy document for the electricity sector adopted by the MoE calls for the development of a competitive market in line with provisions in the treaty, including structured bi-lateral contracts, a Day Ahead Market (DAM) and a Balancing Market (BM). There are several challenges to be overcome in the implementation of such a market, including some legacy commercial arrangements that will persist for several years.

**Current market environment**

The current market model in Georgia provides for bilateral contracts between generators, distribution companies and a small number of large consumers of electricity – many of the contracts are between distribution companies and the power plants that they own or manage. With the exception of small HPP plants, generation prices are capped for privately owned HP plants, and are fully regulated for the state owned Enguri/Vardnili cascade which supplies around 40% of total generation. There is a ‘balancing’ market operated by the Electricity System Commercial Operator (ESCO) which buys un-contracted supply at the capped tariff and resells at the weighted average cost, based upon the regulated tariffs. Although participants are not prevented from directly importing electricity, in practice imports are managed by ESCO. ESCO sells around 15% of the annual total consumption.

Turkey is the main export market following the commissioning of a 700MW 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 HPP has priority access to transmission capacity, and during the
deficit period in the winter months is paid for internal supply at the price paid by ESCO for generation, typically thermal generation.

The bilateral contracts exist between distribution companies and generators or ‘Direct Customers’ (those connected to the transmission network) and generators, and are generally for a volume of electricity to be delivered over and agreed time, perhaps weeks or months in duration. They 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 Direct contracts represent approximately 20% of internal demand (excluding Abkhazia).

There are various MoUs in place agreed between the MoE and electricity sector entities, including:

- MoU with post 2008 small HPP which have unrestricted priority access to the HVDC interconnector to Turkey
- An arrangement with Telasi, the Tbilisi distribution company regarding tariffs which lasts until 2025

**Market Design**

With the construction of the two 350MW HVDC connections to Turkey, there is an opportunity for Georgia to export significant volumes of electricity into Turkish Wholesale market. However, one of the primary concerns of the government is that opening the whole of the Georgian electricity market to competition would drive up wholesale prices towards those experienced in Turkey, which are considerably higher than those in Georgia.

This is because it is thought that if all of the generation fleet were permitted unrestricted trade with the highest bidder, then internal buyers on the Georgian market would be forced to compete directly with Turkish buyers. This is not unreasonable, since a large proportion of the HP would be diverted to Turkey (or bought internally at Turkish prices). This effect would be exacerbated by the introduction of a properly structured and liquid day ahead market as such markets theoretically clear at a price close to the System Marginal Price which would be significantly higher than the current method of pricing at Average Weighted price, which is heavily influenced by the very low Hydro tariffs.

Using the example of 2013, a relatively dry year with a larger than average volume of Thermal and imports in the mix, the average weighted tariff of generation was 4.08 tetri/kWh. If just 12% of supply had to be paid for at 12¹ tetri/kWh to keep it in the country this would drive the average price up to 6.2 tetri/kWh, an increase approximately 50%. 12% of production represents an average of 20% of the HVDC capacity of 700MW. Clearly, these prices will represent the market value of electricity, but this would result in an increase in overall end consumer tariffs of some 18%².

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¹ 1 EUR = 2.27 GEL, (27/01/2015)
² Source: Calculated from ESCO, 2013 Energy Balance and GNERWC
To mitigate this potential tariff shock, the implementation of the model is designed to retain some price control over tranches of hydro, and to gradually release increasing levels of generation into the competitive market, at a pace controlled by the policy decisions made by government. The design calls for two markets to run in parallel:

- a regulated market based on a single buyer or pool structure, with a ‘public supplier’ supplying and billing all non-eligible customers within their respective geographical area at prices mandated by the regulator; and with a portfolio of dedicated generators to that market.
- A competitive market organised bilaterally with over-the-counter (OTC) contracts between the participants, and anonymous power exchanges mechanisms for balancing, day head, and in the longer term derivatives and intraday markets. Customers in this segment that are not connected to the HV network would access the market through ‘independent suppliers’, which may include subsidiaries of the existing distribution companies.

These markets are isolated from each other to ensure that there is no opportunity to resell tariff priced power in the competitive market. It is unavoidable that under some circumstances electricity will flow between the market segments, and there are provisions to manage those flows. The implementation is in 5 stages to minimise risk, retain price control in the regulated sector and to ensure there is sufficient time for participants and consumers to absorb the changes.

**Stage 1 – Establishment**

The objective of Stage 1 is to establish the necessary institutions, systems and procedures and begin limited trading in a low risk environment – at this stage, only OTC and Day Ahead trading would be available; the balancing mechanism and market for ancillary services remains under regulation. This would remain the ‘active’ stage for some considerable period of time to bed in the systems and processes, and build experience and familiarity amongst the trading counterparties. Before market opening it would be necessary to:

- Draft and approve the required amendments to the law on electricity and gas and the market rules
- Functionally unbundle distribution from supply
- Establish the new ‘public supply’ organisations to service non-eligible customers
- Establish ‘independent supply’ organisations to service eligible customers supplied from the distribution networks
- Establish a day ahead market and clearing mechanism
- Familiarize market participants with market rules

Stage 1 would contain most of the market features, but with limited risk and functionality:

- Bilateral contracts would be hourly profiled, specifying the amount of electricity traded for each hour of each day, together with the price
The DAM transactions would accommodate bids or offers for the same volume of electricity at the same price for an hour or a sequence of hours

Imbalances between contacted and actual delivery would be billed at a price based on the regulated pool price

Direct Customers and Independent Supply Businesses would be responsible for settling imbalances

Public suppliers would be obliged to provide hourly offtake forecasts to the TSO to promote discipline in forecasting

It is suggested that the initial tranche of eligible customers are those connected at 6/10 kV and above. This represents about 50% of electricity production but a small number of customers. All such customers would be required to have installed interval meters capable of data-logging consumption in each hour.

To reduce risk, Stage 1 foresees that balancing is managed though the regulated pool that services the non-eligible customers, so balancing prices would be predictable. In the early days of a market, the major motivator for using the Day Ahead Market (DAM) is to mitigate risks in the Balancing Market. Without the incentive of balancing risk, one of the main problems with a DAM in a small market such as Georgia is a lack of liquidity. It the volume of trades is small there is a risk that the clearing price will not be representative, and that the market may not be able to clear at all. Therefore, it is also suggested that the TSO should procure electricity for system losses through the Day Ahead market to encourage liquidity.

The generation available for export should also be considered at this stage. Small HPPs operating under MoUs ensuring access to export markets should have the appropriate interconnector capacity allocated. Any spare capacity should be sold through the bids and offers on the Day Ahead market, either to the external importer or via a local independent supplier.

**Stage 2 - Consolidation**

Once the stage 1 environment is stable (12 months after implementation or longer), the next stage is to introduce a fully functional Balancing Market, to enable the TSO to procure electricity required to maintain instantaneous balance. This will introduce real risk for market participants and will:

- provide strong incentives for market participants to provide accurate hourly forecasts for the TSO to prepare schedules
- Incentivise trading on the Day Ahead market, thus improving efficiency

More sophisticated products should also be made available in the Day Ahead market. At this stage, the TSO should also procure some ancillary services competitively, for example primary and secondary reserves, voltage support.

The market will remain limited to 6/10KV and above with interval metering.
Stage 3 – Roll out to non-interval metered customers

Once all of the mechanisms of the first two stages are working efficiently, the next tranche of eligibility may be rolled out, to medium sized commercial customers without interval meters. This will require some major changes in the systems and processes to enable the balance responsible parties to establish their actual versus real positions for each hour of the day. This will set the stage for a roll out to household customers in the future. In the absence of a full roll out of smart meters with data logging capabilities, it will require an exercise in customer profiling to establish different usage patterns for the various customer classes. From there, algorithms to attribute imbalances to each balance responsible party must be developed and tested.

It is suggested that a commercial customers with an annual consumption of greater that 25MWh be permitted to enter the market, representing around 65% of total consumption.

Later Stages

Once all features of the market are functioning reliably, smaller commercial customers should be introduced to the market, until, when appropriate, full retail choice is implemented.

Other features, such as intra-day trading and a derivatives market may be made available as confidence in the reference price from the DAM increases.

Supply to Abkhazia

Currently, the cost of supplies of electricity to Abkhazia are not recovered. Abkhazia takes approximately 20% of total supply and approximately 35% of the output of Enguri/Vardnili. Until a political solution is found, the electricity market must take account of this. It is understood that the producers and service providers are currently fully paid, so the existing distribution tariffs must take Abkhazia costs into account. There are a few ways to accommodate this in the model:

1. Abkhazia is treated as being served by Enguri/Vardnili: the available capacity from is reduced by 33% and the regulated tariff increased by 50%; Enguri bills for injections minus Abkhazia supply
2. Abkhazia supply is treated as a technical loss and the TSO has a tariff for and procures sufficient electricity to cover the inclusive losses
3. Each generator ‘contributes’ 20% of production to Abkhazia and that is taken into account in the tariffs or offers, depending on the market segment

Option 3 will not be attractive to foreign investors, it would be difficult to manage and it would corrupt the ‘least cost dispatch ‘imperative in the regulated market segment.

Option 1 is the simplest and easiest to manage, and insulates the competitive segment from the Abkhazia issue until the final stage of the market.

Option 2 is the most transparent and will most accurately reflect the costs of supplying Abkhazia over both market segments, and is therefore recommended.
Impact on Tariffs
Tariffs in Georgia are generally low, and while compensating the operational spend of generators, it is likely that the real costs are not recovered. This is a form of subsidy to end consumer tariffs, and subsidised tariffs are recognised to be an inefficient and poorly targeted method of support of providing support which frequently shifts the burden to other sectors of the economy through implicit subsidies. However, it is difficult to introduce reform where such methods are in use without significant preparation, and the model allows for the implementation of policy that permits the management of customer tariffs while preparations are made to protect vulnerable customers through means other than discounting electricity tariffs.

Preparation
Clearly, there is a much preparatory work to be carried out before moving to a new market model, for example:

- Consultation committees to debate the detail of design have to be formed
- Any necessary changes in the Law on Electricity and Gas and any other affected primary legislation
- A new set of market rules must be drafted and agreed covering all aspects of the competitive and regulated market, including balancing rules, settlement rules, financial guarantees, dispute etc.
- New institutions have to be created and new licenses drafted
- Transitional rules for the implementation of the various stages must be drafted
- Significant training of participants and service organisations has to be undertaken
- Public awareness of the process and benefits should be addressed

The list is far from exhaustive. These actions are not a result of this specific market design, they are necessary whatever the target model looks like.

1 Introduction

1.1 Objectives
The specific objectives of the assistance were:

- To assist and advise on the development of the market model
- To assist with the definition of the roles and responsibilities of the market operator in the various phases of market evolution, and their interfaces with other organisations, including:
  - Transmission System Operator,
  - Relationships with the regulator in terms of market reporting and monitoring;
  - internal electricity traders,
  - importers and exports of electricity;
- To assist in the review of outputs from other working groups to ensure compatibility with the market model and the directives of the third package; and
- To transfer of knowledge regarding the experience of other countries in the development of statute and mechanisms for transition to a market model.
The objectives have been achieved by the collaborative development of a market model with the functionality proposed in the GEMM2015 strategy and Electricity Trading Mechanism, which provides a pathway to full implementation of the conditions of the Energy Community Treaty while providing the Ministry of Energy the tools to manage the implementation of the model to minimise transitional risk and to control any impact on household tariffs.

1.2 Key Deliverables
The present report addresses the following main issues:

- the background and rationale for the development of a competitive market;
- examples of electricity market developments in European Countries
- the organisations active in the market and their roles and responsibilities
- the interface between market segments
- mechanisms for managing market imbalances, t
- the trading environment,
- the likely impact on household tariffs
- a roadmap to implementation

1.3 Framework of the Report
This report comprises an Executive Summary, Abbreviations and five sections.

The Executive Summary and Abbreviations are provided at the beginning of this report.

Section 1 comprises this brief introduction.

Section 2 discusses the basic forms of electricity market.

Section 3 discusses the proposed market design.

Section 4 considers the impact upon tariffs

Section 5 draws a brief conclusion

2 Power Markets

2.1 Introduction
Electricity Supply Industries have in most places started out as vertically integrated organisations fulfilling demand for electricity in their local areas. The domains were typically town or city wide, and as electrification spread over wider areas, consolidation of the individual entities occurred until large monopolies emerged. Many of the monopoly organisations had responsibility for supplies to the whole nation and became departments of government; in other countries like the USA the organisations remained in private hands. Where a privately owned monopoly exists, there is opportunity for organisations to exercise their monopoly power to generate disproportionate profits to the disadvantage of the consumers of the product or service. To mitigate that risk, regulation was
introduced to limit the powers on the monopolies and impose various duties upon them to compensate for their monopoly advantage.

The advantages of the integrated model are clear: co-ordinated planning of the different aspects of the enterprise and transaction cost are minimised since electricity transfers are internal. However over recent years, the efficiency of the regulated model has been challenged, and competitive models have evolved in several countries, with varying degrees of success.

The key elements in the design of a power pool are the

- Regulation
- Electricity Market Structure
- Power Pool participants
- Roles and Responsibilities
- Products to be traded
- Transmission access and pricing

2.2 Pool Model

In an integrated utility, the System Operator has the responsibility to despatch generation to meet the required consumption in the most economically efficient manner that maintains the integrity and stability of the system. This is achieved by the System Operator having an intimate knowledge of the cost profile of all of the plant under his control so that the lowest cost plant is dispatched to meet the instantaneous system load, taking into account the demand profile going into the future. Using his knowledge, a ‘stack’ of appropriate generation is constructed in a low to high cost order and is despatched until demand is satisfied.

A pool or single buyer model shares many of the characteristics of an integrated system, except that the system operator is no longer interested in cost – generation is despatched on the basis of price. The complexity lies in the setting of price, which is based upon offers from generation to sell their electricity for a given price for a given volume for a given time, usually broken into hourly or half hourly slots. All electricity that uses the transmission network must be bought and sold through the designated Single Buyer entity.
In the Single buyer model, there are two logical functions required for the system – that of Market Operator and that of System Operator. The Market Operator takes care of the commercial activities in the market while the System Operator fulfils the traditional role of ensuring that load is served in the most economical manner while maintain system parameters. The roles are highly complementary and are sometimes combined into a single entity sometimes known as the ‘Pool Operator’.

For each hour of each day, the Pool Operator establishes a demand profile by establishing the individual demand for each wholesale Consumer and summing the demand for each hour:
Figure 2: Demand Profile

The demand is calculated in time delineated blocks, typically an hour or half an hour in duration known as the ‘trading interval’. This provides the profile of consumption which must be served in the day.

Having established the required demand, the market invites offers from suppliers who wish to sell electricity during that hour. The offers will include the volume of energy that they wish to sell and the price. They will also contain technical details necessary of dispatch such as ramp up rates and minimum generation. The offers are ‘stacked’ in ascending price order, and when demand for the particular trading interval is satisfied, the price of the last generator to qualify for the stack sets the price for the whole of the stack. This price is known as ‘System Marginal Price’ (SMP). Note that some generation is ‘must run’ (e.g. Nuclear or run of the river Hydro plant) and may choose to offer their power at zero price; they will then receive SMP for their production.

Generators at or below SMP are scheduled to be dispatched and are said to be ‘in merit’; those that have offered above SMP are out of merit. In practise, the generators that are actually dispatched may differ from this merit order when other elements are taken into consideration in the global optimisation such as: congestion in transmission lines, start up / shut down / ramp up costs are taken into account.

Depending on the rules of the individual pool, generators may also be asked to offer ancillary services or they may be required to provide them as a condition of participation and be compensated at a regulated rate.

Figure 3: Derivation of System Marginal Price
In the above example, in the hour starting 0400 Generators 1 to 4 are in merit and will receive $20/MWh for their generation; at 0700 Generator 1 - 7 are in merit and will receive $65/MWh and at 2000 all generators are in merit and will receive $100 MW/h.

In the pool model, the System Marginal Price has a tendency to be set by a relatively small number of generators who operate on the boundaries of consumption profiles. As may be observed from the above graph price increases sharply at 6:00, perhaps when more expensive thermal generation has to be dispatched; and again at the peak hours between 8:00pm and 10:00pm.

Wholesale consumers will pay Pool Purchase Price (PPP) for their consumption, which is the SMP plus various regulated uplifts to cover the cost of ancillary services, transmission losses and Use of System etc. Note that where out of merit plant has to be dispatched, the plant is paid at its offer price (“pay as bid”) and the cost recovered through the uplift mechanism.

Note that with this model there is no demand side input into the pricing of electricity, they must rely on the Pool Operator to schedule dispatch efficiently and market forces to ensure that the SMP is close to the true marginal price of generation for the period. Both SMP and PPP are quite unpredictable and are subject to significant volatility and it is common for generators and wholesale consumers to try and manage the risk through Contracts for Difference (CFD). These are financial contracts in which a generator and wholesale consumer will agree an SMP for a particular time and volume that both are comfortable with (the Strike Price). When the SMP is known, the beneficiary of the difference between the SMP and the strike price pays the disadvantaged party the difference between the two thus ensuring that both parties settle at the strike price.

2.3 Bilateral Market
### 2.3.1 Bilateral Contracts

A Bilateral Market is a structure which is based upon individual contracts between buyer and seller, freely agreed between the parties in which the seller agrees to instruct the System Operator to inject a given amount of electricity into the grid at a given time, and the buyer agrees to extract the same amount of power at the same time. Theoretically, the contract may be agreed for any period from a single trading interval to several years. They may have daily and/or seasonal profiles, and may have several different prices. However, some restrictions may be placed upon the term by the market rules for example to prevent abuse of market power. Generally, long term contracts will be used to secure baseload, and as real time approaches, shorter and shorter contracts will be agreed to enable the match between contracts and real time dispatch to be as close as possible.

Agreements may be entered into at any time up until the point at which the Pool Operator is unable to respond to any further adjustments and needs to plan the schedule for the trading interval provided transmission capacity is available. At this time, buyers and sellers must inform the pool operator of the amount of electricity they intend to inject and extract from grid in the relevant trading period. The notification from the generator is called a “Physical Notification”.

The point at which the Physical Notifications are made is commonly called ‘gate closure’. The set of notifications from all generators and imports represents the self-dispatch schedule for the relevant trading interval, and the Pool Operator is obliged to dispatch the generation according to the Physical Notifications unless there is some technical reason why not.

Typical for failure to dispatch reasons are:

- Failure of generation plant of transmission lines
• Transmission Congestion
• ‘Long Market’, i.e. the sum of the Physical Notifications is greater than the sum of demand.

Gate Closure should be as close to real time as possible to give buyers and sellers the maximum opportunity to tune their contracts as accurately as possible. The length of time is generally a function of the IT systems which enable the Pool Operator to react to the notifications, and range from 1 hour in mature markets with sophisticated IT, to 1 day in less developed environments.

Note that transmission congestion is handled in one of two ways depending on circumstance:

• Transmission access is procured prior to the energy contract without which the energy contract is not permitted. If procured through auction, the value of scarce resource will be high and the auction price therefore reflects the cost of the congestion. If allocated with the energy contracts, then the difference in cost between the optimal and alternative resource will indicate the cost of the constraint.
• Through the Balancing Market. If the congestion is caused by a technical failure, the contracts will not be able to be dispatched and balancing energy will be utilized in place of it. The cost of the balancing energy will reflect the congestion cost.

2.3.2 The Balancing Market

In the bilateral market, contract obligations between buyer and seller are settled without reference to the actual generation and offtake, so if A has sold 200MWh to B at $50 MWh, then B pays A $10,000 at the settlement time regardless of how much A has generated and B consumed. If A has several contracts to sell to different buyers and B has several contracts to buy from different sellers, then at the end of the settlement period, A will receive the sum of his contracts and B will pay the sum of his different set of contracts. The differences between contracted and actual delivery, and contracted and actual consumption are considered to be sales and purchases to the System Operator, who uses the energy to keep the whole system in physical balance and who is counterparty in a mechanism managed by the Market Operator to measure and price the differences (described below). Hence the term ‘Net Pool’ which is sometimes used as a synonym for ‘bilateral market’ – the pool transactions are net of the bilateral contracts which make up the bulk of the sales. Note that the roles of System and Market operator are sometimes merged and referred to as ‘Pool Operator’.

Once all of the Physical Notifications have been arranged, the System Operator will consider his own demand forecast for the trading interval and decide if the market is

• Long – expected supply exceeds expected demand
• Short – expected supply is less than expected demand
The Market Operator will invite offers from participants to increase generation or reduce consumption, and bids to increase consumption or reduce demand. Both bids and offers will include the maximum and minimum amount of electricity to be transacted and the price.

2.3.2.1 *Balancing Market Operation*

Once the Physical Notifications are received and the Pool Operator has arranged access to the appropriate resources, the system enters real time. In real time, the System Operators prime responsibility is to ensure the safety and security of the system while respecting, as far as is possible, the physical notifications he has received. Resources will be dispatched as appropriate, and then after the trading period has finished the meters will be read and the final positions of the participants will be calculated:

*Table 1: Balancing the market*

<table>
<thead>
<tr>
<th></th>
<th>Buyer 1</th>
<th>Buyer 2</th>
<th>Total Sales Contracts</th>
<th>Actual Production</th>
<th>Balancing Trades</th>
</tr>
</thead>
<tbody>
<tr>
<td>Seller 1</td>
<td>100</td>
<td>70</td>
<td>170</td>
<td>150</td>
<td>-20</td>
</tr>
<tr>
<td>Seller 2</td>
<td>20</td>
<td>120</td>
<td>140</td>
<td>180</td>
<td>40</td>
</tr>
<tr>
<td>Total Purchase Contracts</td>
<td>120</td>
<td>190</td>
<td>310</td>
<td>330</td>
<td>20</td>
</tr>
<tr>
<td>Actual Consumption</td>
<td>160</td>
<td>170</td>
<td>330</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Balancing Trades</td>
<td>-40</td>
<td>20</td>
<td>-20</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note that sellers will be paid for their contracted supply at the contract price and buyers will pay for their contracted consumption regardless of the actual consumption in the trading interval. So subject to their flexibility, a seller will offer to be paid to increase generation at a price at or above his
marginal cost and will offer to pay to reduce generation at a price below his marginal cost; a buyer will be paid to reduce consumption at a price higher than his contract price and will pay to increase consumption at a price lower than their contract.

### 2.3.2.2 Balancing Market Pricing

Offers to increase generation or reduce consumption are Balancing Market ‘sells’, bids to reduce generation or increase consumption are balancing market ‘buys’. Once the offers and bids have been received, the Pool Offer will rank the Sells in descending price order and the Bids in ascending price order:

**Table 2: Balancing Market Pricing**

<table>
<thead>
<tr>
<th>Offer to Sell</th>
<th>Offers $</th>
<th>MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>130</td>
<td>30</td>
</tr>
<tr>
<td>S2</td>
<td>135</td>
<td>20</td>
</tr>
<tr>
<td>S3</td>
<td>140</td>
<td>10</td>
</tr>
<tr>
<td>S4</td>
<td>145</td>
<td>20</td>
</tr>
<tr>
<td>S5</td>
<td>150</td>
<td>20</td>
</tr>
<tr>
<td>S6</td>
<td>155</td>
<td>2</td>
</tr>
<tr>
<td>S7</td>
<td>165</td>
<td>10</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Bid to Buy</th>
<th>Bids $</th>
<th>MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>B1</td>
<td>25</td>
<td>30</td>
</tr>
<tr>
<td>B2</td>
<td>22</td>
<td>20</td>
</tr>
<tr>
<td>B3</td>
<td>20</td>
<td>10</td>
</tr>
<tr>
<td>B4</td>
<td>15</td>
<td>20</td>
</tr>
<tr>
<td>B5</td>
<td>10</td>
<td>20</td>
</tr>
<tr>
<td>B6</td>
<td>8</td>
<td>2</td>
</tr>
<tr>
<td>B7</td>
<td>8</td>
<td>10</td>
</tr>
</tbody>
</table>

The two tables above show a set of bids and offers for a particular hour in a market. If the Pool Operator decided that the market was 70MWh short, he would accept offers from Sellers S1 through S3 for the full amount of their offers but only 10MW from S4, as highlighted in blue. Each will be paid the price they offer. The Pool Operator sells the energy through the balancing market to those who take more than their contracts at the average weighted price, so in the example the price would be:

\[
\frac{(130 \times 30) + (135 \times 20) + (140 \times 10) + (145 \times 10)}{70} = \$135 \text{ MWh}
\]
In the example on the right, the market is long by 60MW. The Pool Operator would agree to receive payment for all of the electricity from Buyers B1, B2, and B3. The average price paid for consumption in excess of contract or generation lower than contract would be:

\[
(25 \times 30) + (22 \times 20) + (20 \times 5) = \frac{\$23.45}{55} \text{ MWh}
\]

The above simplified case assumes a single balancing price. In both cases, participants taking more electricity than contracted would pay for the difference, those taking less would be compensated for the difference.

### 2.3.3 The Day Ahead Market

Because of the risks inherent in the balancing market, participants want the ability to lock in prices for as much of their demand as possible before real time to minimise the amount of electricity they need to procure through the BM. Depending on the individual buying and hedging strategies, long term contracts may be entered into to secure seasonal baseload, medium term contracts to secure conservative daily shapes, and short term contracts to tune the position close to real time as more precise demand forecasts become available. The following figure shows a typical contracted profile for a day:

![Consumer Contracts Diagram](image-url)
In this example, a contract for baseload has been secured perhaps a year ahead of the day, when prices were favourable. As the demand forecast increases in accuracy, further contracts are added to the shape until the contracts reflect the next day’s demand. The final short term contract may be added a day before, or even hours before, in some markets, real time.

The problems with arranging a contracts in the very near term are:

- Finding a counterparty
- Ensuring the price paid is in line with the market.

A Day Ahead Market (sometimes referred to as a Spot Market) is often the vehicle used to simplify the process. The Spot Market may be run by an independent company – a Power Exchange – and remunerated by commission charged on each deal, or may be operated by the Market Operator and paid for through a fee system. The objective of the Spot Market is to match sellers of electricity at a price that buyers are prepared to pay and sellers are prepared to buy. The difference between this and bilateral contracts are that the buyers and sellers are unknown to each other and the PE acts as counterparty in all of the deals and guarantees payment. In practise, the Spot Market may match many sellers with a single buyer and vice versa. The Power Exchange will require security from all buyers to ensure that it is able to meet necessary payments.

Contracts in the Spot Market are highly standardised, with only the price and quantity being subject to negotiation. There no technical qualifications, it is assumed that if a generator offers a quantity of electricity then it is fully available.

In principle, the market is operated as follows:

- At some moment, the Power Exchange opens a trading interval for auction. This may be a day ahead, a week ahead or any time between.
- For the trading interval, the Power Exchange invites offers from participants to sell electricity quoting volume and price, and bids from participants to buy electricity, again quoting volume and price.
- Bids may be submitted and withdrawn at any time up to gate closure.
- At gate closure, the auction is closed and all bids and offers on the table at that time are binding.

Once all bids and offers are in, they will be matched, and a market clearing price calculated. The clearing price is the value at which the supply and demand curves intersect:
In the figure above, the volume of electricity on offer to sell increases as the price increases, and the amount of electricity that participants are bid to buy decreases as price increases.

- At point A ($20/MWh) buyers would buy 78 MWh if it were available, but sellers are only prepared to sell 9 MWh at that price
- At point B ($50/MWh) sellers would be prepared to sell 49 MWh but buyers are only prepared to buy 14 MWh
- At point MCP, the market clearing price, buyers are prepared to buy 32 MWh at $33/MWh and sellers are prepared to sell 32 MW at $33 $/MWh. The market is said to have cleared.

Once the market clearing price has been established, all sellers with prices up to and including the MCP will be dispatched and will be paid the MCP, and all those with bids over the MCP will receive the requested electricity and will pay the MCP.

There is a further complication in that the Transmission System Operator must ensure that there are no transmission constraints that prevent the dispatch of the matched power. If there are, the market
will be ‘split’ into 2 separate markets on each side of the constraint, and the matching process repeated. This will give rise to two different MCP values, which will be a valuable indicator of the cost to the system of the transmission bottleneck.

In the regional context, the effect of transmission wheeling on prices must also be taken into account when matching bids and offers.

The Spot market managed through a power exchange does provide an economically efficient method of pricing electricity and ensuring available transmission capacity is used optimally. However, there needs to be a large number of bids and offers to enable the discovery of the MCP, which economic theory indicated should be close to the marginal price. In the absence of such liquidity, it is likely that the derived MCP will be distorted, or that a clearing price may not be found.

In markets with low liquidity, a more appropriate method may be one in which the day ahead bids and offers are posted on a bulletin board to enable potential buyers and sellers to discover each other.

2.4 Power Pool Participants
A key feature of any power pool is the definition of organisations that are permitted to trade electricity in the pool and may include:

- Regulated Supply Companies (which may be the local distribution company in integrated structure, or may be a separate entity. The ‘distribution’ activity – evacuating electricity from the high voltage network to the end user – is not a pool activity, but may be a service supplied to the pool);
- Large end user organisations: Generally, organisations who consume electricity in bulk and have a connection to the HV network;
- Load aggregators, i.e. organisations who buy bulk power on behalf of several end users and either re-sell it to them or take a commission on savings;
- Generators with connections to the high voltage grid;
- ‘Portfolio’ Generators, i.e. organisation that own and manage several power stations and wish to arbitrage their dispatch internally; and
- Import and export agents.
### 2.4.1 Roles and Responsibilities

The following table outlines the roles and responsibilities in the Single Buyer Market and Bilateral markets. The roles of System Operator (SO), Transmission Operator (TO) and Market Operator (MO) are considered separately for each role even though the roles may be combined into a single entity.

**Table 3: Roles and Responsibilities in single buyer and bilateral markets**

<table>
<thead>
<tr>
<th>Role</th>
<th>Single buyer</th>
<th>Bilateral Market</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Generator</strong></td>
<td>Offers electricity to pool at self-determined prices for each trading interval. Despatched centrally by system Operator. May have an obligation to provide ancillary services, or may offer to SO depending on market design.</td>
<td>Strikes bilateral contracts with buyers at mutually agreed prices. Offers balancing electricity to pool at self-determined prices for each trading interval. Notifies system operator of contract position and self-despatches subject to technical constraints. May have an obligation to provide ancillary services, or may offer to SO depending on market design.</td>
</tr>
<tr>
<td><strong>System Operator</strong></td>
<td>Commitment and Economic dispatch of generation units based on least cost principles. Operation of the system within the safety standards specified within the Interconnection Code. Establishment and management of operating reserves.</td>
<td>Commitment and dispatch of generation units according to their declared intentions for the trading interval. Procurement and deployment of balancing electricity. Maintenance of system operating parameters.</td>
</tr>
<tr>
<td><strong>Transmission Operator</strong></td>
<td>Operations and maintenance of the high voltage network</td>
<td>Operations and maintenance of the high voltage network</td>
</tr>
<tr>
<td><strong>Market Operator</strong></td>
<td>Manages the commercial elements of the pool, processing offers from Generators to fill the demand forecast at the optimal price. Bills buyers for generation and other services and receives payments from them. Pays Generators, TO etc. Billing and payment procedures depend on the arrangements established in the market rules.</td>
<td>Receives notice and notifies SO of contracted electricity supply at each of the injection points to the grid. Seeks offers and bids for balancing electricity on behalf of the SO. Provides settlement service for traders and service providers. May run day ahead spot market in more sophisticated and liquid markets.</td>
</tr>
<tr>
<td><strong>Seller</strong></td>
<td>Notifies SO of availability and technical data, availability and offer price for energy. Obeys SO instructions to run where there is</td>
<td>Enters into bilateral agreements with buyers. Notifies SO of contracted deliveries for the trading interval. Offers spare</td>
</tr>
<tr>
<td>Role</td>
<td>Responsibilities</td>
<td></td>
</tr>
<tr>
<td>--------------</td>
<td>----------------------------------------------------------------------------------</td>
<td></td>
</tr>
<tr>
<td>Regulator</td>
<td>Oversees Market and Interconnection Code and manages process for amendments. Enforces adherence to rules. Ensures no abuse of market power. Sets tariffs for transmission, use of distribution grids (where appropriate), ancillary services (for services that do not have a market) and other services were separated (e.g. MO services, SO services). Sets retail tariffs. Arbitrates in disputes between Pool Participants. Oversees Market and Interconnection Code and manages process for amendments. Enforces adherence to rules. Ensures open access to the transmission network. Sets tariffs for transmission, use of distribution grids (where appropriate), ancillary services (for services that do not have a market) and other services where separated (e.g. MO services, SO services). Sets retail tariffs where monopoly supply model for end users is in place.</td>
<td></td>
</tr>
</tbody>
</table>

In both the single buyer and the bilateral market, the transmission operator is not a participant but is a regulated service provider mandated by regulation to provide open access to all members at regulated tariffs. In the bilateral market, the System Operator is a trading member in that he buys and sells balancing electricity, but the commercial activities of the SO should always balance to zero.

Both market structures require a Market Operation function, which may be combined with the System Operator or may be separated.
3 Current System

3.1 Overview

Until relatively recently, the Georgian Electricity sector was plagued by unreliable infrastructure, unmanageable levels of debt and an inability to meet consumer demand, particularly in the winter. Many of these problems stemmed from poorly managed distribution companies, particularly outside Tbilisi, where there was a plethora of uncontrollable ‘city gates’ distribution companies who collected payments for electricity from consumers and failed to use those funds to pay for generation and transmission services. The consequence of the poor collection rates was an increasing dilapidation in the electricity sector infrastructure because of the lack of maintenance, supply shortages because of increasing debt to foreign countries affecting imports of gas for TPPs, and direct imports of electricity.

Among the measures taken to resolve the problem was the sale of the Tbilisi Distribution Company and units 9 and 10 of the Mktvari TPP to the American owned AES. AES made many improvements to the management and operations, but following the destruction of unit 10 in an explosion and constant difficulties with the then Government, AES finally sold their assets to RAO UES, who continue to own Telasi and the TPP, which are now operated on a sound commercial basis.

Later, with the exception of the Tbilisi, Adjara and Kakheti distribution companies, all of the other companies were consolidated into a single organisation known as the ‘United Distribution Company’ (UDC). After a difficult start, the company was placed under a USAID financed management contract, which restructured the company and improved collection rates towards international norm. The company was then sold to Energo-pro, who later acquired the Adjara distribution company, and now also operating on a sound commercial basis.

Now that the system is operating with a reasonable degree of reliability and has some financial stability, it is timely to migrate from the ‘crisis’ mode of operation to a new environment which enables coherent planning for the system and the introduction of market disciplines to encourage efficiency and flexibility for the stakeholders.

3.2 Electricity Sector Structure

The electricity sector in Georgia has been legally unbundled into generation, transmission, and distribution, (which includes the supply function). The majority of generation is in private hands; the exceptions are two of the large HP stations, Enguri and Vardnili, which remain in state hands and are classified as ‘regulatory’ stations. There are three privately operated gas fired thermal plants which are designated as 'reserve' plant and are dispatched in the winter; there is an obligatory purchase from wholesale buyers from these plants. There are three distribution companies, JSC Telasi serving Tbilisi, JSC Kakheti Energodistributsia serving the Kakheti region in the east, and JSC Energo-Pro Georgia which serves everywhere else. Telasi and Energo-Pro also own generation assets and each has a generation licence.
Generation

Electricity Generation in Georgia is provided by a mix of Gas and Hydro Power plants and some renewable power stations; some are privately owned and operated, some wholly owned by the state. Current installed generation capacity totals 3,330 MW\(^3\) and in 2012 total generation was approximately\(^4\) 9.7 TWh. Total consumption was 10.1 TWh:

In 2012, the generation mix was made up as follows:

- HPP - 7.2 TWh
- TPP - 2.5 TWh
- Imports - 0.62 TWh

During the same period, 528 GWh were exported making Georgia a net importer in 2012, partly because of unfavourable hydrological conditions.

During the spring and summer, there is a surplus of hydro power in Georgia, opening up export opportunities. In the winter, the electricity balance includes both thermal and imported electricity.

Transmission Structure

The transmission system operator is the Georgian State Electro system (GSE). The organisation is a Joint Stock Company, 100% owned by the state. It owns the Transmission lines with voltages below 400kV, the 500/400 kV lines are owned by Energotrans which is a subsidiary of GSE. The 500 kV interconnector with Russia is jointly owned by Sakrusenergo, a subsidiary of RAO UES, and Energotrans. GSE is the only dispatch licensee.

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

A 500/400 kV HVDC connection to Turkey was commissioned in 2013; small recently constructed HPP (RES) has priority access to the line. Spare capacity is sold through an auction managed by GSE.

Distribution and Supply Structure

In Georgia, distribution and supply are integrated and there is no opportunity to choose supplier for customers connected to the distribution network. All three distribution companies are privately owned. There is competition at the wholesale level, with 6 energy intensive users taking electricity directly from the transmission network based on bilateral contracts with generators.

\(^3\) Source: GSE Annual Report 2012

Commercial Operator

There is a market operator in the sector, the 'Electricity Sector Commercial Operator' (ESCO) which has the responsibilities to settle the contracts, buy and re-sell balancing electricity through the market and arrange import/export contracts. ESCO also settles the reserve energy provided by the thermal plants in the winter season.

3.3 Current Market Structure

The market model is based on bilateral contracts between the Generators, the 3 distribution companies and the eligible electricity intensive customers. Tariffs are set for all power stations except those below 13MW installed capacity. Wholesale buyers and small HPP built since 2008 have the ability to create their own 'basket' of contracts from the available sources to suit their own needs at prices that are subject to a regulatory cap.

![Financial Contracts in the Georgian electricity system](image)

In the figure above, the blue arrows designate Direct (bilateral) Contracts, the red arrows designate balancing transactions.

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 particular obligation to notify the TSO of intended delivery for any particular hour. GSE dispatches according to recognised operational practice, taking account...
of demand, reservoir levels, state of TPP plants, import contracts etc. For this reason, the contracts are considered to be financial rather than physical.

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. Not that this means that the relationships between the contracting parties is limited. If a generator has a contract with more than one distribution company and the distribution company has contracts with more than one generator, it is impossible to allocate supply between the parties. In practice, most contracts exist between distribution companies and their own generation assets so the problem does not arise.

Almost 90% of generation is sold to energy companies and energy intensive customers on bilateral contracts at fixed or capped regulated tariffs. The remainder is defined as balancing energy, managed by the market operator 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.

4 Proposed Market Model

4.1 Background

Georgia is a country that is generously endowed with hydro power, affording the opportunity to supply most of its internal demand with low cost, clean electricity. In a typical year some 80% of demand is met by hydro resources, the balance being met by thermal power plants (TPP) and imports. The availability of hydro power is seasonal, with surpluses in the summer and deficits in the winter when much of the rainfall in the mountains falls a snow. Demand also peaks in the winter.

With the exception of new build, hydro tariffs are low in Georgia, with much of the old stock fully depreciated, and without any value for water being included in the tariffs. The TPP is run as baseload in the winter, with HPP picking up the peak load. While the existing OCGT plant is not as efficient as modern CCGT (there is a plan to construct a CCGT station at Gardabarni), they benefit from low gas prices negotiated with Azerbaijan, so again TPP tariffs are relatively low. The low energy prices lead to advantageous retail electricity tariffs in the country.

With the new 400/500kV 700MW HVDC interconnector that came into service in 2013 and the planned new investment in interconnector capacity to all of the neighbouring states, Georgia has a greater opportunity to access external markets for electricity and to take advantage of higher prices to export electricity. However, if international trading was unrestricted, this would result in an increase in internal tariffs as the Georgian distribution companies would have to compete for their wholesale supplies with buyers in higher priced markets.

Georgia is actively progressing with its application to join the Energy Community, which implies the full adoption of the Acquis on Energy, albeit with the possibility of derogations on some of the
conditions. One of the underlying principles is of the acquis is the creation of an internal European market without barriers to inter-state trade, which if fully implemented in a single transformation would cause an unacceptable tariff shock to the people of Georgia.

The market model is designed to be compliant with the acquis in the long term but to allow a controlled implementation of full competition. This is achieved by reserving some portion of generation capacity for the internal market, and introducing competition to the remainder.

4.2 Design Principles

The design objective is to create the systems, procedures and capabilities that will enable the migration from the environment to a model that has a clear route to full implementation of the Energy Community acquis in a manner that permits the risks to be controlled for participants in terms of trading risk and for retail customers in terms of impact on tariffs. The design must be capable of full EnC compatibility (derogations may apply short/medium term to permit evolution) and must be capable of delivering protection to non-eligible customers in the short to medium term:

- the concept of full customer choice must be supported
- the model must provide for commercially unrestricted 3rd Party access to transmission network for qualified organisations
- Distribution and supply must be unbundled to allow Third Party Access to the distribution network

Until the market fully opens:

- A proportion of generation will be reserved to supply the dedicated to non-eligible customers
- No leakage of dedicated generation at regulated tariffs into the competitive segment
- captive and competitive segments must be segregated and appropriate procedures put in place to manage physical flows between the two markets

This is achieved through a phased implementation strategy comprising of 5 stages. The first and most critical stage re-organises the existing structure into a hybrid pool/bilateral form, defines the roles and responsibilities in the market and prepares the market rules and other necessary document and agreement pro-formas, establishes the systems, procedures and interfaces and procures, configures and tests the relevant software tools. Stage 1 is a simplified and low risk form of the market and should result in little or no impact upon tariffs in the regulated sector.

Stages 2 through 4 introduce new products and trading tools and increasingly pushes risk (and opportunity) out to the participants where it belongs. Household tariffs will still depend upon supplies from tariff priced generation and should remain affordable. Stage 5 is the roll out to household customers – at this stage the market enters full completion and tariffs become less predictable. By Stage 5, the measures necessary to protect the vulnerable customers should be in place.
4.3 Market Segments

The design envisages a hybrid model with two parallel markets: a centrally dispatched segment with regulated price controls serving the shielded consumers while allowing competition on an initially small but growing competitive segment.

As noted above, to maintain tariffs in the regulated market, it will be necessary to reserve generation to serve the non-eligible customers. To facilitate that, Enguri/Vardnili should not be made available to the competitive market.

In the regulated segment, electricity provided to the non-eligible customers by generation other than Enguri/Vardnili (including Thermal) would be priced at the capped tariffs set by GNEWRC, using the standard tariff mechanisms currently in use. All of the generation required to service the regulated market would be dispatched under the control of the TSO.

The competitive segment would be able to strike their own contracts between generator and load, bilaterally or through a power exchange managed by the market operator. It is important that this sector does not gain access to tariff generation, as this would create distortions in the market. However, it is clear that under some circumstances electricity will flow between the two markets; the settlement for such flows will be managed by the market operator.
## 4.4 Market Actors & relationships

<table>
<thead>
<tr>
<th>Actor</th>
<th>Role in Regulated Market</th>
<th>Role in Competitive Market</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulator</td>
<td>Regulatory oversight of both market segments</td>
<td></td>
</tr>
<tr>
<td>TSO</td>
<td>Planning and dispatch of regulated generation</td>
<td>Dispatch according to contract (subject to technical constraints), procurement and dispatch of balancing electricity, procurement of ancillary services</td>
</tr>
<tr>
<td></td>
<td>System short, medium and long term planning, procurement of balancing electricity and ancillary services, maintenance of system within technical parameters</td>
<td></td>
</tr>
<tr>
<td>MO</td>
<td>Financial settlement of energy flows</td>
<td>Manages Power Exchange, repository of bilateral contracts, settlement of balancing transactions for out of balance participants</td>
</tr>
<tr>
<td></td>
<td>Manages financial flows between markets</td>
<td></td>
</tr>
<tr>
<td>DSO</td>
<td>Manages distribution networks</td>
<td></td>
</tr>
<tr>
<td>Clearing House</td>
<td></td>
<td>Settles transactions on the power exchange, provides payment guarantees for sellers</td>
</tr>
<tr>
<td>State Regulated Generation</td>
<td>Dispatched by TSO, provides energy to regulated market place</td>
<td>Provides balancing energy to the deregulated segment when necessary.</td>
</tr>
<tr>
<td>Private regulated Generation</td>
<td>Provides balancing energy when necessary at regulatory capped prices</td>
<td>Establishes supply contracts with buyers on the competitive market. Informs TSO of contracted position for use in dispatch schedules</td>
</tr>
<tr>
<td>De-regulated Generation</td>
<td>Sells to MO at SMP</td>
<td>Unrestricted trading in the competitive and export markets</td>
</tr>
<tr>
<td>Public Supply Business (PSB)</td>
<td>Organisation procuring electricity through the Market Operator for sale to non-eligible customers</td>
<td></td>
</tr>
<tr>
<td>Independent Supply Business (ISB)</td>
<td></td>
<td>Supplier able to procure electricity from generation or import sources and resell to eligible customers including export markets</td>
</tr>
<tr>
<td>Direct Customers</td>
<td></td>
<td>Large Customers connected to the Transmission Network able to contract directly with Generators</td>
</tr>
</tbody>
</table>

*Figure 9: Market Actors*
Figure 10: Contractual Relationships

Figure 10: Contractual Relationships above shows the contractual relationship between the various actors in the market. Physical relationships are always under the management and control of the TSO, regardless of the market segment being served.

The TSO plans dispatch on the basis of the contracts from the bilateral market which are treated as ‘must run’ units (subject always to safety and technical constraints), and the forecasts from the public suppliers. Contracts are aggregated by the Market Operator and the aggregated position for each Grid Supply Point is provided to the TSO.

The centrally dispatched regulated market works on a least cost dispatch model. The TSO dispatches generation on the most economically efficient manner, taking into account the management of reservoirs, the cost of imports and the management of the Thermal generation fleet. The competitive market is characterised by bilateral trading between market participants, either directly or via a power exchange.

The sum of the requirements from the competitive and regulated segments are summed together, compared with the TSO’s own forecast, and arrangements are made by the TSO for the procurement of any balancing electricity that may be required.

The inevitable physical flows between the participants are, as always, managed by the TSO, but the financial arrangements are managed by the MO. The exchanges are treated as balancing flows by the TSO, the pricing of which will depend upon the direction of the flow and the rules in the current stage of implementation.
4.5 Stage 1 - Establishment

The objective of Stage 1 is to establish the institutions, systems and procedures required to establish the market in such a way as to minimise transactional and operational risk. This will be achieved by opening the market to a limited number of customers and restricting trading to a limited number of product options. The output of Enguri and Vardnili will remain dedicated to the regulated market at tariffs imposed by GNEWRC; and balancing energy will be available at GNEWRC tariffs. **This should ensure that there will be little or no increase in tariff customer prices as a result of market opening.**

In preparation for Stage 1, several large and complicated tasks have to be addressed, for example:

- Consultation committees to debate the detail of design have to be formed
- Any necessary changes in the Law on Electricity and Gas and any other affected primary legislation
- A new set of market rules must be drafted and agreed covering all aspects of the competitive and regulated market, including balancing rules, settlement rules, financial guarantees, dispute etc.
- New institutions have to be created and new licenses drafted
- Transitional rules for the implementation of the various stages must be drafted
- The existing DSOs must be (at least) functionally unbundled into and supply and distribution network businesses (DNO).
- The unbundled supply business turn into the Public Supply Businesses (PSB) responsible for servicing non-eligible customers in their geographical territory. Any generation assets must reside in the supply business, as the acquis on energy does not permit control of generation to lie with the same organisation as the DNO
- Tariffs for the DNO and Public Supplier must be unbundled and applied
- Independent Supply Businesses (ISB) must be created to service the eligible customers that are not Direct Customers
- Existing Direct contracts between Generators and DSOs must be terminated. If either party wished to mitigate price risk in the new pool, equivalent contracts for difference (CfD) may be considered, but price risk is very small.
- Significant training of participants and service organisations has to be undertaken
- Public awareness of the process and benefits should be addressed

It is proposed that the competitive segment should consist of Direct Customers plus 6/10 kV upwards customers - approx. 50% of production but a small number of customers. The vast majority of customers will remain in the regulated market at this stage; the impact will be minimal.

Undoubtedly, there would be problems encountered in the systems and processes after the initial implementation. It would be reasonable to allow 1 year for the market and participants to be ready for the implementation of the next stage.
4.5.1 Stage 1 Regulated Market segment

Capacity from Enguri/Vardnili and other generators which has not been contracted in the competitive market is available to the TSO, who dispatches generation according to least cost principles, taking into account prudent reservoir management. In the interests of security of supply, the TSO will plan and dispatch TPPs and will coordinate with the MO to secure imports of electricity when necessary. Electricity destined for the regulated market that is not sourced from Enguri/Vardnili will be considered to be balancing electricity and will be settled by the Market Operator. To maintain a reasonable price parity between household and commercial tariffs, it will be necessary for the regulated pool to include the same proportion of thermal and imported electricity in their generation mix as the proportions of regulated and commercial demand.

In the regulated market, the new Public Supply Business (PSB) will be responsible for all sales of electricity to non-eligible customers. As a local monopoly, tariffs and service quality obligations will be under the control of GNEWRC. Public Suppliers are provided electricity out of the regulated pool, which is intrinsically self-balancing. However, the PSB will have responsibility for providing annual, monthly and daily consumption forecasts to the TSO to enable accurate planning in the system. In later stages of the market, the PSB will have a balancing responsibility, complete with incentives and penalties.

The PSB will pay the MO for electricity and will recover the costs from non-eligible customers at the tariff for the customer classes set by GNEWRC. The MO in turn pays the generators for their metered injections.

It is likely that the PSBs will be subsidiaries of the existing distribution companies.

4.5.2 Stage 1 competitive market segment

Contracts in the competitive market

It is proposed that the competitive segment at Stage 1 includes all customers who are supplied at 6/10kV or above. This represents 50% of total production and 40% of current DSO demand. All customers of this type must have interval meters installed capable of recording hourly consumption volumes.

Direct Customers may contract directly with generators for their supply, but those connected to the distribution network will require an intermediary to manage the relationship with the DNO and to accept responsibility for balancing. To accommodate this, the design envisages the establishment of an Independent Supply Businesses, who will have the ability to establish contracts with generators and customers, will take part in trade on the Day Ahead market, and will have a balancing responsibility towards the TSO. It is likely that the initial ISBs will be subsidiaries of the existing distribution companies; however over time new ISBs may appear, for example as sellers to aggregate supplies of small HPPs, or as buying organisations representing commercial groups.

Contracts will be based on a standard template to facilitate processing. It is envisaged that there will be a ‘master agreement’ established between each buyer and seller, which will establish the
commercial obligations between them, thus enabling a relatively simple schedule to be agreed for each contract which defines the amount and time of supply. The contracts will be firm and will be hourly profiled.

The Market Operator will have the role of registrar of all of the contracts at these voltage levels and will have the responsibility to inform the TSO of aggregate position of all of the participants with a balancing responsibility for each Grid Supply Point (GSP).

**Balancing**

The counterparties to the TSO in the balancing regime are the Direct Customers who are connected to the Transmission Network, and the ISBs who manage the eligible customers who are connected to the distribution networks. The electricity balance is measured at the interface between the transmission network and the Direct Customer or the transmission network and the relevant distribution network. The interface is often referred to as the Grid Supply Point (GSP). Within the GSP there may be customers of several different ISBs, and the contribution of each one to the net imbalance must be calculated. This is facilitated at Stage 1 by requiring all eligible customers to have interval metering installed. Via contract notifications provided by the MO, the TSO will be aware of the contracted net position for each GSP.

As noted above, the regulated market is self-balancing, as there is no contract for a specific injection or offtake off electricity, hence there is no contractual variance to accommodate. In the competitive market, there is a specific commitment established by the contracts and therefore a mechanism to reconcile actual and contracted volumes is required.

The TSO is the party responsible for the safe operation of the system, and it is the TSO who must maintain the instantaneous balances. This is usually managed by raising or lowering the amount of electricity injected in the system, although demand side techniques are increasingly popular. It is very much in the interest of the TSO to encourage the accuracy of the forecasts of the participants, which is achieved by passing of the financial risk of being out of balance to the participants. Generally, the prices for balancing electricity are unpredictable and participants wish to tune their positions to be as close as possible to the actual consumption or delivery.

However, in Stage 1 of the market, risk is intended to be minimised. To achieve this, there will be no market for balancing electricity. Instead it may be managed by the within the regulated market as follows:

- If an ISB or Direct Customer takes more electricity than contracted in any hour, the excess will be charged at the average pool price; if less is taken it will be compensated at average pool price
- A regulated generator in the competitive segment will be paid at the regulatory cap for the difference between the contracted obligation and the actual production (which may be negative)
• If a de-regulated generator supplies more than the contracted value, the compensation will be at the price of the pool generator with the highest tariff in the hour, if less is supplied then contracted the shortfall will be charged at the average weighted price for the hour.

Note that the ISB is responsible for settling the imbalances for its customers, even though the variance has been caused by the customers. The ISB must make its own contractual relationship with its customers to recover the costs, which may be established by the records from the interval meters installed on their premises.

‘Shadow prices’ for balancing energy should be calculated and published for every hour, based on the highest cost of energy in each day. While this may not be an entirely accurate representation of true balancing prices, the mechanism should provide participants with a ‘soft landing’ to appreciate the risks and encourage accuracy.

**Day Ahead Market**

The Day Ahead Market (DAM) is a power exchange providing for anonymous trades between buyers and sellers. It gives participants the opportunity to tune their contracts ahead of real time to match as closely as possible their supply and consumption, and provides a reference or spot price to inform decision making. DAMs are typically two sided blind auctions, meaning the sellers offer volumes and prices at which they are prepared to sell, buyers bid for volumes and prices that they are prepared to pay to the DAM operator, who then establishes a clearing price the maximises the volume of trades. The buyers and sellers cannot see any other parties’ bids or offers. The strike price is the price at which offers at and below the strike price are satisfied and bids at or above the strike price is satisfied. The sellers are paid and the buyers are paid at the strike price. The market closes at some set time before real time; the timing varies from country to country depending on the maturity and sophistication of the systems. It is recommend at 24 hours for Georgia in the first instance.

There are many different products possible in a day ahead market, allowing participants to bid for complex profiles of contract to satisfy their needs. However, to avoid risk, it is recommended that in the first incarnation, trading is kept simple, being restricted to the same volume and price for each hour or consecutive block of hours.

To be able to work efficiently, the DAM needs to be highly liquid, often a problem for smaller markets. To encourage liquidity, it is suggested that:

- The TSO sources some electricity, perhaps 50% to represent the proportion of electricity in the competitive market.
- Regulatory surplus may be offered only through the Day Ahead Market.

**Export Market**

Over recent years, there has been an incentive for investors building small (less than 13MW) HPPs. The incentives are:

- In the summer, the SHPPs have priority access to the Turkish market through the 400/500kV HVDC interconnector, and are at liberty to sell their power at whatever price they negotiate.
For the 4 winter months they sell their output to the MO at the price of the highest cost generation in the market, which is generally the TPP.

The incentives were designed to make the projects feasible in a low tariff environment with the objective of diversifying supply and encouraging renewables. In the EU, such projects are usually incentivised by the adoption of feed in tariffs, which provides a higher level of comfort for the investments. However, for as long as the contracts should be honoured for as long as they persist.

Until some future date when the Turkish and Georgian markets may be coupled, the remaining capacity on the interconnector should be auctioned, as happens now.

**Ancillary Services**

In addition to Balancing Services and Losses, the TSO must also procure and deploy other Ancillary Services, typically:

- Instantaneous Frequency Response
- Primary and Secondary reserves
- Tertiary reserves
- Voltage Support
- Black Start capability

For Stage 1 it is proposed that these services are provided from pool generation, as the existing tariffs must compensate for these services. However, the Guaranteed Capacity charges paid to Thermal plant in the winter may also be considered as an Ancillary Service, since these payments are made to help ensure the security of the system. Since the whole market benefits from the availability of these reserves, it is proposed the Guaranteed Capacity from TPP is be considered to an ancillary service and procured directly by the TSO. To accommodate this, it would be necessary to include the costs directly in the TSO tariffs. The costs vary from year to year, for example in 2010 they contributed 0.2 tetri/kWh; in 2013 they contributed 0.4 tetri/kWh.

**Regulatory Enhancement**

Even though there are relatively few eligible customers in this early stage of market opening, it is necessary to introduce new regulations to enable GNEWRC to protect customers in the new environment. At least the following powers should be included:

- Market Monitoring
  - Definitions of prohibited behaviour
  - Regulators power to penalise
  - Information requirements
- Customer Protection
  - Obligations of suppliers
  - Supplier of last resort legislation
  - Rights of customers
4.6 **Stage 2 – Consolidation**

Once the systems and processes required in Stage 1 have matured and the market participants have become accustomed to the new trading environment, the some of the artificial protection should be lifted. It is not proposed that there should be any change to edibility at this stage.

As in Stage 1, there would be problems encountered in the systems and processes after the initial implementation. There is also significant work required to prepare for Stage 3. It would be reasonable to again allow 1 year for the market and participants to be ready for the implementation of the next stage.

4.6.1 **Balancing Market**

In Stage 1, there was little real incentive for accurate forecasting and tuning of real time contract positions, because the cost of balancing electricity was unlikely to deviate far from the norm. Now in Stage 2 it is proposed that the ‘soft’ prices used in Stage 1 are abandoned, and the Balancing Market becomes subject to a market approach managed by the TSO.

Having established a view on the contracted position of the competitive market segment (which may be affected by transmission constraints), the TSO will conduct an auction in of bids and offers for each hour in which:

- Generators offer to increase injections, customers (ISOs and Direct Consumers) offer to decrease load
- Generators will bid to decrease injections, customers will bid to increase load

From the offers and bids, the TSO will calculate a Balancing Settlement Price (BSP) based on the Accepted bids/offers as appropriate. The value of the BSP may be the average or marginal price from the auction, depending on how aggressive the incentives should be. Participants who are short on their contracts (deliver less or consume more) will pay the BSP, those who are long will be paid the BSP.

Clearly, if a participant has the opposite position to the overall system, the penalties are likely to be lower – a long (overproduction compared to contract) generator in a short system may find the BSP to be quite reasonable.

It is proposed that at this stage of the market the average BSP are used and if at some later stage the incentives prove not to be sufficiently strong, the marginal prices are adopted.

It may also be prudent to consider some incentive for the PSBs to improve accuracy of forecasting, because it is the small commercial and household sector which are much more likely to cause imbalance that the relatively predictable large consumers. As the market continues to open more balancing risk will pass from the PSBs to the ISBs.

4.6.2 **Ancillary Services**
It is possible at the stage to release some other ancillary services to market competition. In terms of reserves, while Enguri/Vardnili may be capable of proving for much of the requirement, reserves must also be available in the event of, for example, a transmission outage preventing the evacuation of electricity on the 500kV Imereti or Khartli lines. Voltage support must also be in reasonable proximity to the likely source of voltage instability.

Both of these services may be procured competitively at this stage.

4.7 Stage 3: Roll out to commercial non hourly metered market

This stage represents a significant development in market implementation, when the emphasis moves to encompass organisations at the lower voltage levels, and whose consumption does not warrant interval metering.

The major change is in the administration of the balancing market, because it will no longer be possible to directly measure the actual position of the ISBs. To accommodate the changes, new rules must be introduced.

In Georgia, the majority of non-hourly meters are read every month thus avoiding many of the issues caused by timing differences, and so reasonably accurate estimates of total consumption per GSP per supplier should be available. However, 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, in the UK representative classes are:

- Households unrestricted
- Households on time of use tariffs
- Commerce unrestricted
- Commerce with time of use tariffs
- 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 from the ISB and PSB records, the load profile for each class is applied to establish the hourly load for each ISB and the PSB connected to the GSP. For each ISB, the load from their interval metered customers for each GSP is added and the final hourly load is calculated.

From there, the contracted amounts are compared with the actuals and imbalances calculated.
At this stage of market development, the self-balancing regime in the regulated market should be abandoned, and the PSBs should carry responsibility for their demand forecasting by becoming liable for balancing fees.

From the simplified explanation above, it is clear that significant systems development will be necessary to manage the market, and some sampling required to establish typical profiles in the customer classes.

It is recommended that once development is finished, the next tranche of commercial and industrial should be moved into the competitive market. Some research would be necessary to establish the threshold, but perhaps in the 40MWh annual consumption, or a maximum demand of 10kW.

4.8 Stage 4 Derivatives
Some 60% of demand should now be served by the competitive market, but it remains small in terms of customers. There is a strong probability that liquidity remains low and a large proportion of the trade in electricity is through bilateral agreements at commercially confidential prices.

To improve liquidity, it may now be appropriate to introduce some derivatives trading; forwards, futures, CfDs etc. This should improve liquidity and stabilize the reference price in the day ahead market, thus encouraging more transaction and reducing bi-lateral volume.

4.9 Roll out to households
Once all of the stages above are well established in the market, the move to full choice may now be considered. This will entail all of the complexity of designing customer switching rules and systems, competition in tariffs, managing debt transfers, managing vulnerable and delinquent customers, establishing suppliers of last resort etc. This is also the point at which any protection from the rigors
of the marketplace will be taken away from customers as the state relinquishes control of the sector. There are many social consequences that must be considered and addressed before this step is taken, and it is out of the scope of this document.

However, once the market has progressed to Stage 3 and can manage the mechanics of competition, the possibility for customer choice exists.

5 Impact on Tariffs

The wholesale market can only influence the input price of wholesale electricity – it cannot of itself drive improvements in network operations or in the cost of customer service. Responsibility for oversight of the regulated generation, networks and PSBs falls into the domain of the regulator, as does the task of policing the activities of the wholesale market. In the Independent Supply Businesses, competition is perceived to be the best driver of performance.

The major impact on tariffs will not be as a result of internal completion in Georgia, it will be as a consequence of generation companies gaining access to foreign markets and internal buyers having to compete for supply.

In considering the tariffs, this report assumes that the generation tariffs set by GNEWRC are a reasonable reflection of the full costs incurred in generating electricity, and would therefore approximate prices in a competitive market on an annualised basis. It should be noted that many of the Hydro tariffs are based on fully depreciated assets, and the TPPs benefit from low, regulated gas tariffs that are a consequence of the advantageous gas purchase contracts agreed with Azerbaijan. Changes in the cost of generation would have a material impact on regulated tariffs, regardless of the market design.

5.1 Abkhazia

The way that Abkhazia consumption is treated has a material impact on tariffs. There is no charge made to Abkhazia for electricity, and Abkhazia represents a large proportion of demand, 18% in both 2010 and 2013. Since Abkhazia is in the energy balance, and since there is no reported shortfall of funds, it must be assumed that there is sufficient income encapsulated in the current end user tariffs to cover the cost of supply to Abkhazia. Effectively, this means that the real cost of electricity generation supplied within Georgia is some 20% higher than that expressed in the generation tariffs.

If all of the Abkhazia supply is considered to be taken from Enguri and Vardnili, that will have the effect of driving household tariffs up, since more balancing power will be required from the market. If it is supplied from the Competitive side, then that will have the impact of driving commercial energy prices up, which would not be helpful in the economy. So, it appears sensible for the purposes of this study to treat Abkhazia supply as a virtual transmission loss and, as now, share the

5 Source: ESCO Energy Balances
cost over the whole of the sector. The recommended mechanism for this is to treat Abkhazia as a technical loss for which the TSO should procure electricity through the appropriate mechanism, depending on the stage of roll out of the market.

5.2 Generation costs
Generation costs in Georgia are sensitive to the hydrology in any given year – broadly, the greater the rainfall the lower that average cost of electricity, as some of the winter thermally generated electricity and imports are avoided. Wet years also increase the available capacity for export.

To review generation costs in Georgia, two years were chosen: 2010, which had favourable hydrology and 2013 which was relatively dry.

The amount of energy consumed in the two years was similar, approximately 9.9 TWh in both years, and the cost of distribution and transmission changed very little, but because of lower precipitation the price of wholesale electricity in 2013 was 60% higher than that in 2010. The difference was driven by thermal generation and imports:

Figure 12: Service cost comparison 2010/2013
Source: Inogate, derived from ESCO energy balances and GNEWRC tariffs
<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thermal Generation (GEL x 10^6)</td>
<td>672.21</td>
<td>1,744.10</td>
</tr>
<tr>
<td>Imports (GEL x 10^6)</td>
<td>21.84</td>
<td>47.18</td>
</tr>
</tbody>
</table>

Table 4: Thermal and Import costs for reference years

Source: Inogate, derived from ESCO energy balances and GNEWRC tariffs

Figure 13: Monthly comparison of Thermal cost

Source: Inogate, derived from ESCO energy balances and GNEWRC tariffs

Figure 12 demonstrates the seasonal nature of the costs.

As may be noted from the cost breakdown in Figure 12, the proportion of the cost of wholesale electricity in the bill of the final customer varied between 17% and 33% depending on the mix of generation, and will probably average around 25% over time. In most European countries which have a high proportion of thermal power, the ratio is generally closer to 60%.

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6 Import prices are not available, but are assumed to approximate to thermal tariffs including guaranteed capacity charges
5.3 Consumption in the Distribution Companies

All tariffs in the 3 distribution companies are set by GNEWRC. The tariffs are split into various classes to enable a fair allocation of cost (customers served at a high distribution voltage incur lower cost per unit to serve), and to provide some level of ‘social’ tariffs to assist the less affluent members of society.

<table>
<thead>
<tr>
<th>Distribution</th>
<th>2010</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>6 - 10</td>
<td>10.94</td>
<td>10.85</td>
</tr>
<tr>
<td>35 - 110</td>
<td>8.25</td>
<td>8.26</td>
</tr>
<tr>
<td>Commercial</td>
<td>13.46</td>
<td>13.42</td>
</tr>
<tr>
<td>Budgetary</td>
<td>13.48</td>
<td>13.46</td>
</tr>
<tr>
<td>Residential Up to 101 kWh</td>
<td>8.12</td>
<td>8.20</td>
</tr>
<tr>
<td>Up to 101-301 kWh</td>
<td>10.88</td>
<td>10.96</td>
</tr>
<tr>
<td>302+ kWh</td>
<td>14.95</td>
<td>14.93</td>
</tr>
<tr>
<td>Non Graded</td>
<td>13.55</td>
<td>13.55</td>
</tr>
<tr>
<td>Total</td>
<td>11.94</td>
<td>11.20</td>
</tr>
</tbody>
</table>

Table 5: Average Distribution Tariffs
The tariffs have not changed in the two reference years; but do vary slightly between distribution companies. The variations are caused by changes in the mix of customers in the categories.

5.4 Regulated generation prices in the new market

In the new market model, it is propose that all generation supplied to the non-eligible market via PSBs will continue to be regulated by GNEWRC. The monthly average price of generation varies according to the mix of plant that is dispatched - the PSBs will absorb the price variations within the year, as customer charges per kWh remain constant according to the tariff class listed above.

<table>
<thead>
<tr>
<th></th>
<th>Jan</th>
<th>Feb</th>
<th>Mar</th>
<th>Apr</th>
<th>May</th>
<th>Jun</th>
<th>Jul</th>
<th>Aug</th>
<th>Sep</th>
<th>Oct</th>
<th>Nov</th>
<th>Dec</th>
<th>AWT</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>3.72</td>
<td>3.41</td>
<td>2.83</td>
<td>2.69</td>
<td>2.67</td>
<td>2.64</td>
<td>2.28</td>
<td>2.16</td>
<td>3.03</td>
<td>3.81</td>
<td>3.87</td>
<td>4.36</td>
<td>3.10</td>
</tr>
<tr>
<td>2013</td>
<td>5.96</td>
<td>5.90</td>
<td>4.81</td>
<td>2.89</td>
<td>2.82</td>
<td>2.75</td>
<td>2.79</td>
<td>3.41</td>
<td>3.43</td>
<td>3.31</td>
<td>6.24</td>
<td>6.14</td>
<td>4.24</td>
</tr>
</tbody>
</table>

Table 6: Monthly generation costs (tetri/kWh)

Even though the individual tariffs for the various power plants remain the same, the impact of the season and hydrology and costs is clear.

The market design envisages reserving a sufficient generation from the internal fleet of hydro and thermal plant (in the proportions of regulated and competitive demand) to service the non-eligible customers at tariff imposed by the Regulator, thus isolating non eligible customers from the risk generation costs rapidly tending to those experienced in Turkey. The suggested allocations include:

- Output from Thermal plant being allocated between the two markets in the same ratio as forecast demand for each market
- HPP being allocated first to the regulated segment in the order
  - Enguri/Vardnili
  - Other regulatory stations
  - Run of river stations
- Guaranteed capacity charges for TPP spread evenly through each market according to consumption (most easily achieved by treating them as transmission expenses)

Losses and supply to Abkhazia are also socialized into transmission expenses.
Assuming that players in the competitive market are able to negotiate contracts close to the tariffs mandated by GNEWRC, the impact on the cost of generation in the regulated tariffs and competitive consumer costs would be:

<table>
<thead>
<tr>
<th>Year</th>
<th>Class</th>
<th>Jan</th>
<th>Feb</th>
<th>Mar</th>
<th>Apr</th>
<th>May</th>
<th>Jun</th>
<th>Jul</th>
<th>Aug</th>
<th>Sep</th>
<th>Oct</th>
<th>Nov</th>
<th>Dec</th>
<th>Av. Wt Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>Non Eligible</td>
<td>3.55</td>
<td>2.61</td>
<td>1.49</td>
<td>1.41</td>
<td>1.34</td>
<td>1.32</td>
<td>1.32</td>
<td>1.33</td>
<td>2.28</td>
<td>2.33</td>
<td>2.48</td>
<td>2.61</td>
<td>2.05</td>
</tr>
<tr>
<td></td>
<td>Eligible</td>
<td>4.74</td>
<td>4.82</td>
<td>3.88</td>
<td>3.21</td>
<td>2.97</td>
<td>2.91</td>
<td>2.33</td>
<td>2.23</td>
<td>4.00</td>
<td>5.27</td>
<td>5.59</td>
<td>6.89</td>
<td>3.89</td>
</tr>
<tr>
<td>2013</td>
<td>Non Eligible</td>
<td>6.44</td>
<td>5.37</td>
<td>4.58</td>
<td>2.11</td>
<td>2.06</td>
<td>2.03</td>
<td>1.76</td>
<td>1.71</td>
<td>2.11</td>
<td>2.06</td>
<td>6.02</td>
<td>6.15</td>
<td>3.69</td>
</tr>
<tr>
<td></td>
<td>Eligible</td>
<td>8.20</td>
<td>7.38</td>
<td>6.03</td>
<td>3.48</td>
<td>3.21</td>
<td>3.18</td>
<td>3.36</td>
<td>4.33</td>
<td>4.49</td>
<td>4.28</td>
<td>7.09</td>
<td>7.12</td>
<td>5.06</td>
</tr>
</tbody>
</table>

*Table 7: Monthly and Weighted Average prices in 2010 and 2013, tetri/kWh*

Source: Inogate, derived from ESCO energy balances and GNEWRC tariffs

It may again be observed that the availability of Hydro Power is highly influential in the cost of generation; the cost of power for the eligible sector in 2013 is almost twice that of 2010. The impact on the competitive sector is slightly less pronounced, as that sector is already taking more of the higher priced electricity in this model. Note that the chart is based on the first stage in the market roll out (6/10kV customers) and that the negotiated prices would be broadly similar to those in the regulated sector.

The strategy for implementation of the market is carried out through a series of stages, culminating in full opening of the market. The following table demonstrates the impact on generation pricing as more commercial customers transfer to the competitive market:
### Table 8: Price variations on customer switching

<table>
<thead>
<tr>
<th>Case</th>
<th>Customer Class</th>
<th>2010</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case, MV Customers only</td>
<td>Eligible Customers Av Wt Tariff</td>
<td>2.32</td>
<td>3.80</td>
</tr>
<tr>
<td></td>
<td>Non Eligible Customers estimated price</td>
<td>3.98</td>
<td>5.34</td>
</tr>
<tr>
<td>Tranche 2, Customers with consumption of 40MWh</td>
<td>Eligible Customers Av Wt Tariff</td>
<td>2.16</td>
<td>3.77</td>
</tr>
<tr>
<td></td>
<td>Non Eligible Customers estimated price</td>
<td>3.92</td>
<td>5.12</td>
</tr>
<tr>
<td>Tranche 3, the bulk of commercial customers</td>
<td>Eligible Customers Av Wt Tariff</td>
<td>2.05</td>
<td>3.69</td>
</tr>
<tr>
<td></td>
<td>Non Eligible Customers estimated price</td>
<td>3.89</td>
<td>5.06</td>
</tr>
</tbody>
</table>

Source: Inogate, derived from ESCO energy balances and GNEWRC tariffs

As the customers move from the regulated market to the competitive, the tariffs for non-eligible customers decrease slightly as more of the high cost thermal and imported energy migrates to the competitive market. If necessary, this may be managed by adjusting the ratios of reserved energy as the market opens.

Again, the chart assumes that the prices for competitive generation will be close to the generation tariffs. Clearly, the prices will not as precisely defined as shown here, there will be many variations as suppliers increase their competencies in forecasting and risk management.

### 6 Conclusions

The electricity industry in Georgia has many challenges and many opportunities. The country has significant geographical advantages over many of the neighbouring countries, with very large untapped hydro potential, and ready markets to the south, east and north in the long term. However, much effort is needed to exploit the opportunities that exist.

One of the primary requirements for the system is investment, and the best potential for securing such investment lies outside of the country. The potential is obvious, but for the investor the risks are also manifest, and one of those risks lies in the lack of competition and transparency in the sector. Whilst a competitive market is not a panacea for all of the problems to be overcome, when matched with the appropriate legislation and regulatory oversight, it does provide a much more stable and predictable environment for the investment community.
Electricity tariffs are low in Georgia when compared to those in Turkey and the west, where the more lucrative markets lie, and where there is an appetite for the low cost HPP that Georgia may inject into that marketplace. The risk is that as a consequence, domestic wholesale electricity prices will rise rapidly towards those experienced in mature market places as wholesale buyers in Georgia have to compete with the external markets. This is a consequence of market integration, but the domestic situation must be managed carefully to avoid unacceptable tariff shocks.

The market design proposed here, when combined with the appropriate legislation and oversight, provides a managed pathway to a liberal market whilst maintain control of internal prices for householders. It does imply the maintenance of subsidies until full market opening is achieved, but it is difficult to propose a transformation that would work without such accommodations.