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PROPOSED APPROACHES TO TRANSITION TO HOURLY BASED ELECTRICITY MARKET IN GEORGIA, STAGE 1

Draft, November 2013

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Acronyms Used in this Report

BM	Balancing Mechanism
CBETA	Cross Border Electricity Trade Agreement
DAM	Day Ahead Market
DAP	Day Ahead Planning - capacities hourly planning for next day
DAS	Day Ahead Scheduling
DC	Direct contract
ESCO	Electricity System Commercial Operator
ETM	Enabling Trading Mechanism
GNEWRC	Georgian National Electricity and Water Regulatory Commission
GEMM 2015	Georgian Electricity Market Model 2015
GoG	Government of Georgia
GTMax	???
GSE	Georgian State Electrosystem
HIPP	Hydropower Investment Promotion Project
HPP	Hydro power plant
MAP	Monthly Ahead Planning – capacities hourly planning for next month
MO	Market Operator
MoE	Ministry of Energy of Georgia
NTC	Net transfer capacity
PX	Power exchange
TPP	Thermal power plant
TSO	Transmission System Operator

1. INTRODUCTION

The Government of Georgia (GoG)'s Ministry of Energy (Moe's) has proposed to develop the Georgia Electricity Market Model for 2015 (GEMM 2015), which will be a major step forward in the development of Georgia's competitive electricity market. GEMM 2015 includes the development of an Enabling Trading Mechanism (ETM), an important first step that will enable new Georgian HPPs to sell electricity into the regional competitive electricity markets (including selling to Turkey, pursuant to the Cross Border Electricity Trading Agreement (CBETA) between the GoG and Government of Turkey signed on January 20, 2012.)

One of the primary goals of GEMM 2015 is the establishment of an hourly balancing market before the start of 2015. Georgia's existing electricity wholesale system consists of informal bi-lateral contracts which are backward-adjusted on a monthly basis to account for the actual power delivered. In contrast, Turkey has an electricity wholesale system that requires participants to make daily forward commitments and be subject to a daily look-back to assess actual energy delivered versus planned. A transition plan is needed for the Georgian power market from the existing "central dispatch and monthly adjustments of bi-lateral contracts" to a new market model, an hourly balancing and settlement system compatible with the Turkish power market.

The transition to this new market model in Georgia should be realized in four phases:

Table 1. Phases of market reform in accordance with GEMM 2015

Phase 1	• Improve scheduling skills for all market participants and service providers • Implement month ahead and day ahead scheduling for bi-lateral contracting on hourly basis • Develop "Day Ahead Planning" concept for all market participants
Phase 2	• Develop of direct "take or pay" bilateral contracting system • Implement DAP • Develop new hourly imbalance service/deviation mechanism;
Phase 3	• Develop and introduce hourly balancing market and settlement system
Phase 4	• Develop and implement day ahead power exchange (PX)

This Report is dedicated to the specific mechanisms of implementing the tasks under Phase 1 and Phase 2, shown in the Table 1. In the course of their implementation, the following main factors should be taken into consideration:

- ➢ Protection of domestic consumers;

- Creation of incentives for private investors into new Georgian HPPs;
- Creation of favorable conditions for traders for beneficial export of electricity.

Reforms should be carried out gradually, by Phases, as noted above, with the principle of not causing unfair burden on any stakeholders.

In all countries the process of transition to the competitive market takes several years, including the period of development, simulation, and the real implementation of new mechanisms.

This document is developed to provide the purpose of day ahead planning and the proposed mechanisms for completing the primary tasks.

It should be noted that the tasks to be solved must comply with a single vision of reform.

The first task is developing the operational regimes for market participants hourly planning.

2. HOURLY PLANNING

Currently planning is done on a yearly basis divided by months, then by days in electricity volumes in MWh.

2.1. HOURLY SCHEDULING

Hourly scheduling is a tool of scheduling for each hour for Day/Month ahead in MW (capacities).Currently, such scheduling for the next day is a dispatch practice when GSE forecasts the total load of the power system and in accordance with it allocates regulated generation resources.

The main difference on a new market is that the scheduled regimes are determined based on nominations of consumers, generators which are sure to be included in the balance in any cases, as well as export and import contracts (if present).

Therefore GSE will plan regimes of part of generators only to ensure hourly power system balance.

All calculations should be performed by daily curves commonly used in the power sector, i.e. to plan the next day balance depending on hourly electricity demand.

Such an approach of planning is usually known as a Day Ahead Planning (DAP).

Day Ahead Planning is a set of actions carried out under the coordination of the Market Operator in order to determine their balance of the forecasted hourly market participant nominations for next the day compared to actual deliveries and receipts to the market.

Day Ahead Planning is a key element for market functioning in four trading sectors:

- Bi-lateral contracts;
- Balancing Market;
- Day Ahead Market (power exchange); and,
- Intraday trading Market.

Such markets correspond to the above-mentioned Phase 4.

The initial step for DAP is a **Day Ahead Scheduling** (DAS) which involves a series of steps, as follows:

- Submission of hourly nominations by market participants;
- Preparation of hourly balances ;
- Regimes verification on the technical feasibility and security by TSO; and,
- TSO's approval of next day dispatch schedule by hours.

This schedule effectively is used for developed markets, however for emerging markets such as Georgia; there are some difficulties for it implementation.

The main problem is the lack of experience of operation on hourly market for the most of the market participants. In addition, there is time limit.

Long-term bi-lateral contracts (or direct contracts as it is called in Georgia) should be saved for year with hourly capacities determination for each month. Daily agreements should be used also (see chapter3).

In accordance with Stage 1 of the reform, the Electricity Trade Mechanism (ETM) consists of both bi-lateral contracts and balancing mechanism. Taking into account that on markets with low competition at the beginning of transition to competitive market the prices in bi-lateral contracts are lower that balancing ones(less efficient generators are used for balancing) the scheduling accuracy is very important.

It is evident that special methodology to transition to hourly based market in Georgia must be created.

In the proposed approach for DAP outlined below MAP and DAS mechanisms are used both, wherein each mechanism has a clear application area.

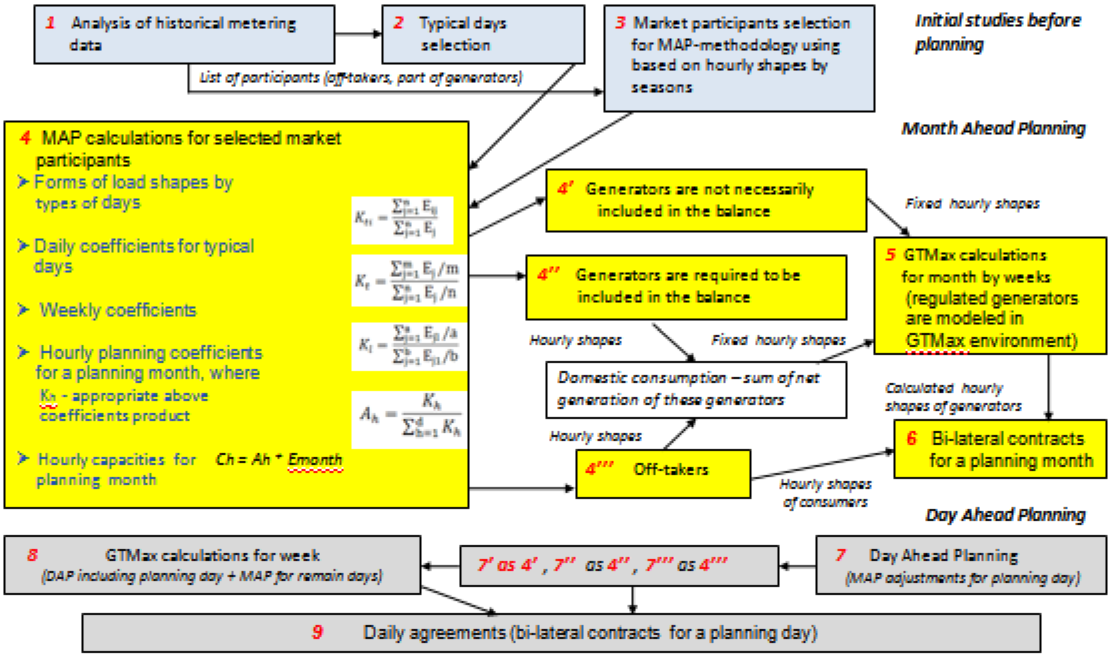
2.2 PROPOSED METHODOLOGY

The proposed methodology includes following phases:

- *Initial studies before planning*
- *Month Ahead Planning*
- *Day Ahead Planning*

Total scheme is shown on Figure 2.1.

Figure 2.1.Steps for hourly planning



2.2.1 INITIAL STUDIES BEFORE PLANNING

In general, market participants can be separated into two groups: (1) those with practically same form of load shape by years and (2) with form depending on system regime (mainly regulated power plants).

This differentiation can be done based on analysis of metering historical data.

It's evident that in first group off-takers (consumption inertia) and run of river HPPs can be included. Some medium and large HPPs can be included also (e.g. even Lajanuri which instead of existing reservoir practically operates with a flat load shape).

Unfortunately the availability of required historical data (electricity sell/purchase points) for market participants does not have much depth (years). In addition GSE's practice should be used for this differentiation.

As a result the list of participants (Group 1) can be determined (step 1 on Fig. 2.1.).

Analysis of load shapes forms will result in a number of typical days (in accordance with proposed methodology the planning must be done by types of day) taking into account the specific of Georgian power system load shapes. It can be assumed that the separation can be carried out for Working days, Saturdays and Sundays+Holidays in contrast to the ex-Soviet dispatch practice when working days were separated on Monday and the rest too (Step 2 on Figure 2.1.).

Before the planning process, it is necessary to refine the list of players that will be able to plan load shapes independently based on historical data(proposed methodology), depending on the seasons (months).Obviously, it will include all off-takers, and clarification applies only to generators (step 3 on Fig. 2.1).

Thus, market players from Group 1 will plan their load shapes without participation of GSE and provide as nominations to GSE for both Month and Day Ahead Planning.

For market players from Group 2, GSE's participation is needed.

It should be noted that the number of participants in the Group 2 is considerably less than in Group 1.

2.2.2 MONTH AHEAD PLANNING

The goal of this phase is load shapes determination for each market participant for each hour for the planning month.

For this two methodologies are used:

- Developed within USAID Hydro Power & Energy Planning Project (HPEP) for market participants from Group 1;
- GTMax currently implemented within USEA project in Georgia for market participants from Group 2.

2.2.2.1 MAP-TECHNOLOGY FOR MARKET PARTICIPANTS (GROUP 1)

A detailed description of a suggested MAP mechanism (Step 4 on Figure 2.1) is presented in Annex 1 of this document. The main body of this report provides a description of the main tasks of MAP development process, to get to the MAP mechanism.

The proposed mechanism consists of the following:

- Receiving and filtering of historical data (1-3 years) on purchase/sale of electricity;
- Sorting by selected typical days;
- Defining the averaged form of the load shape for each typical day of the month; and,
- Adjusting for the difference between electricity volumes by averaged typical day, the weekly dynamics of changes of electricity volumes, and the synchronization of planned and historic years' calendars. The calendar synchronization requires applying and adjusting the current year's weekdays, weekends, and holidays, onto usage periods from the past.

As a result of this process, weighted coefficients are developed for each hour of the planning month and multiplying them by the planned monthly volume results in planning capacities for each hour.

The advantage of the suggested mechanism is that calculation data are used in per unit values and not in absolute values; this allows using such shapes, which are not dependent on a number of factors (water levels, climatic conditions, developing metering system, etc.).

For the realization of this mechanism, special software should be developed and modeling should be initiated.

However, on initial stage Excel model can be created *(see example in Annex 1*)

As a result capacities for each market participant from Group 1 for each hour are determined and can be used in GTMax calculations (see next paragraph) as fixed profiles.

2.2.2.2 GTMAX TECHNOLOGY FOR REGULATED GENERATORS (GROUP 2)

GTMax is the software generation hourly dispatch for a week.

GTMax software was developed by Argonne National Laboratory and marketed by ADICA LLC (USA).

GTMax determines the least-costly method of meeting system loads. It also ensures that market transactions and system operations are within the physical and institutional limitations of the power system. System operators can see where they can shed load on the basis of the incremental costs of utilizing demand-side management options and the marginal cost of energy production. When multiple systems are simulated, GTMax identifies utilities that can successfully compete in the market by tracking hourly energy transactions, costs, and revenues.

The experience of GTMax implementation in Armenia has shown that for success in such power systems as Armenian and Georgian it's needed to create correct flexible system of technical and price restrictions.

Moreover a slight software modification to significantly reduce manual work and convenient output forms to be added.

It should be noted that consumption is a input data for GTMax, therefore must be forecast by other tool (in our case it's a proposed in previous paragraph MAP technology).

Modeling in GTMax taking into account many factors and sufficiently hard (detail description in USAID funded "ASSISTANCE TO ENERGY SECTOR TO STRENGTHEN ENERGY SECURITY AND REGIONAL INTEGRATION" project report "GTMax simulation of the Armenian power system and isolated regimes calculations with assessment of renewable sources", September 2011).

Therefore, the facilitation of GTMax model is very important. This is the first will speed up the process of a model development for Georgia due to a significant reduction of its volume (modeling in GTMax don't required for market participants from Group 1).

As a result of Step 5 (Fig. 2.1) we have hourly capacities for planning month for all market participants and power system hourly balance.

Without going into the details of the calculations here we give only some comments.

On Step 4''' we determined total load of power system by hours (required input data for GTMax) taking into account losses on market or transportation expenses by ESCO (difference between total net generation including import and total consumption including export). These losses aren't transmission or distribution losses. Special methodology for fair allocation of these losses is developed (Annex 2), but initially for market participants the methodology based on average percentage can be used (e.g. this percentage can be determined on appropriate historical data).

Step 4’’ gives us generators for which must be included in balance input and output after GTMax runs load shapes will same (must be included in balance). In the current implementation, this is achieved by specifying prices close to zero or total load of power system can be reduced on their total generation as on Fig. 2.1. In this group particularly new HPPs can be included.

Generators are not required to be included in the balance will be characterized by real or negotiated prices (Step4’). For them, the final load shapes will be determined through GTMax.

Export and Import (can be divided by directions). There are two options: (1) if bi-lateral contracts are exist, the export is entered as off-taker (4’’’) and import as generator (4’’) and (2) in case of lack of contracts the possible export and required import are determined through GTMax taking into account appropriate technical and pricing restrictions based on offers of neighbor countries.

It should be noted that taking into account that GTMax operates by weeks for Month Ahead Planning the period of calculation by GTMax must be 5 weeks. On the other hand MAP methodology provides calculations for the month. It is therefore necessary to add load shapes obtained by MAP up to 5 weeks. It is relatively easy to do based on dynamics of the load shapes for a month.

Determined load shapes are the base for monthly hourly bi-lateral contracts (Step 6 on Fig. 2.1, see chapter 3 also).

2.2.3 DAY AHEAD PLANNING

The DAP implementation will improve the accuracy of planning for a particular day. Month Ahead Planning is performed a few days before the planned month. Obviously, the day ahead planning, especially towards the end of the month will be more accurate.

The procedures for such planning were developed in the framework of the HIPP project.

MAP curves can be used as initial data for the DAP for the planning day. The adjustments of these curves will quickly allow determining the capacities required for off-takers and possible for generators for each hour (market participants from Group 1).

The result is the planned curves of market participants for the (N+1) day, where N is the current day.

DAP involves a series of steps, as follows:

- Submission of bids/offers by market participants;
- Preparation of hourly balances, adjustments (when necessary) agreed with concrete participants;
- Regimes verification on the technical feasibility by TSO with possible adjustments;
- Final regime by hours;
- Daily agreements conclusion

All calculations for regulated power plants (Group 2) in GTMax are performed as for MAP with the following specifics:

- Calculations are performed for one week only;
- For participants from Group 1 for days of current week from 1^{th} to N+1 the DAP curves are used, for days from N+2 to 7^{th} the MAP load shapes are applied (Step 7 on Fig. 2.1).

As a result the load shapes for all market participants for planning day (N+1) are determined (Step 8 on Fig. 2.1).

The difference between daily shape and sum of monthly bi-lateral contracts for each market participant for particular day is a potential for daily agreements (Step 9 on Fig. 2.1, see chapter 3 also).

In this case, the time allocated for the DAP is very limited, especially for the beginning taking into account the absence of hourly market functioning experience for many participants the DAP simulation can be performed for the $(N+2)^{th}$ or $(N+3)^{th}$ days with further transition to $(N+1)^{th}$.

3. BI-LATERAL CONTRACTS ON HOURLY BASIS

According to the approved GEMM 2015, it is necessary to develop new principles of bi-lateral contracting between Georgia's wholesale market participants.

Currently such bi-lateral contracts, referred to as "direct contracts," are executed on a yearly or monthly basis for electricity volumes. This model of bi-lateral contracting has a significant disadvantage, as follows.

If in the monthly profile, the actual volume of electricity of a market participant coincides with the contractual volume, then the purchase of that volume from the balancing market will be zero. However, a monthly deviation of zero does not mean that there were no hourly deviations. If there are hourly deviations, this may seriously deteriorate the power system regime as a whole.

As a result of not capturing hourly deviations, an entity having a negative impact on the regime, and on the functionality of other participants, does not bear any responsibility.

While implementing the new market model operation on hourly basis, it is required that several new mechanisms, in particular direct contracting for the monthly (but on an hourly basis) must be developed and implemented.

Take-or-Pay principle means that a buyer is responsible to pay for a good or a service whether or not it was in fact delivered.

New contracts should operate on a "take or pay" principle and not be backward-adjusted, as is the case in the today's practice.

Application of the "take or pay" principle is a very important difference of the proposed market model.

Another important point is to determine where such contracts are concluded. As a result of discussions with ESCO the point of conclusion is at a generator's node as was earlier. This is why in the above GTMax calculations the consumption includes losses also.

In the framework of this project a methodology of fair losses allocation was developed and proposed, however for the first stage ESCO decided to use losses allocation based on average percentage by months (see Annex 2).

The allocation of losses and their prices for balancing mechanism will be given in Chapter 3.

Let us consider the possible models for the conclusion of bi-lateral contracts.

Three basic models of direct contracting for electricity are possible:

1. Full pool;
2. Partial pool + free negotiation amongst market participants on a monthly basis.
3. Model 2 + daily agreements.

The disadvantages of Model 1 are:

- It is necessary to export power on a monopoly basis, but it contradicts existing legislation;
- Lack of opportunity for market participants in selection of a financing partner;
- Possibility to force small HPPs to sell 100% of electricity in summer at low prices;
- Disabling the use of export as an incentive for investors into construction of new HPPs in Georgia;
- Mutual influence of MAP planning accuracy of one participant on other participants.

The disadvantages of Model 2 are:

- Is that doesn't allow for the covering of all consumption in each hour
- It conflicts with the terms of the first stage of the reform.

M**odel 3**appears most feasible and is considered below in more detail.

There are two proposed types of contracts for planning month (sequence of conclusion does not matter).

<u>Type 1</u> *<u>Partial pool (full matrix)</u>*

The main purpose of this type of bi-lateral contracts is to minimize the generation price for domestic off-takers and also the allocation of this generation between all consumers "fairly by volumes".

At first the generators that participate in this schedule must be selected (their composition can vary by the seasons).

For example, for the summer, when TPPs of Georgia are not operating, the schedule may include only Enguri, Vardinili, etc. (i.e., low cost electricity production). For the winter, when Georgia has a shortage of electricity, the TPPs can be included in this schedule to allocate fairly the expensive electricity among all consumers.

In this mechanism two steps are suggested for realization.

Step 1 - selection of those generators, which mandatorily should participate in the Pool.

Such generators over the whole year are Enguri, Vardinili and probably Zhinvali HPPs as state-owned generators of inexpensive electricity at tariffs approved by GNERC. In this way the protection of domestic consumers will be ensured.

In winter period, when there is deficit of electricity in Georgia, operation of TPPs and import activities are unavoidable. This gas or oil-generated electricity is expensive, however, including the TPPs' generation and import electricity into the partial pool will allow to fairly distributing it between off-takers.

In general it is possible that generators participate in partial pool with part of their generation or may apply for inclusion in the partial pool.

Concerning the off-takers inclusion in the partial pool, then there are possible options.

From the point of view of market liberalization and new players exit to market is advisable to include all consumes in a partial pool without exception.

During discussions with the ESCO was offered the option of incorporating in a partial pool the distribution companies only. Obviously, this is due to the desire to reduce the generation cost for residential. However, in this case, in winter may increase the financial burden on the residential due to TPPs.

The final decision should be taken.

Step 2 - With application of this approach, the electricity generated hourly by each of these generators shall be distributed between the included off-takers according to their portion of total consumption (the principle of full matrix).

	Off-taker 1	**……**	**Off-taker N**
Generator 1	$\mathbf{a_{11i}}$	**……**	$\mathbf{a_{1ni}}$
……	**……**	**……**	**……**
Generator M	$\mathbf{a_{m1i}}$	**……**	$\mathbf{a_{mni}}$

where M – variable by seasons, N – constant or variable in dependence of chosen option.

As a result we will get the same generation price (for each hour it will be different) for the off-takers under these contracts.

It is worth mentioning that electricity off-takers having their own generating plants (e.g. EnergoPro, Telasi) participate in this scheme with the portion of consumption defined as consumption minus own generation in summer and consumption in winter (TPPs and import portion increase).

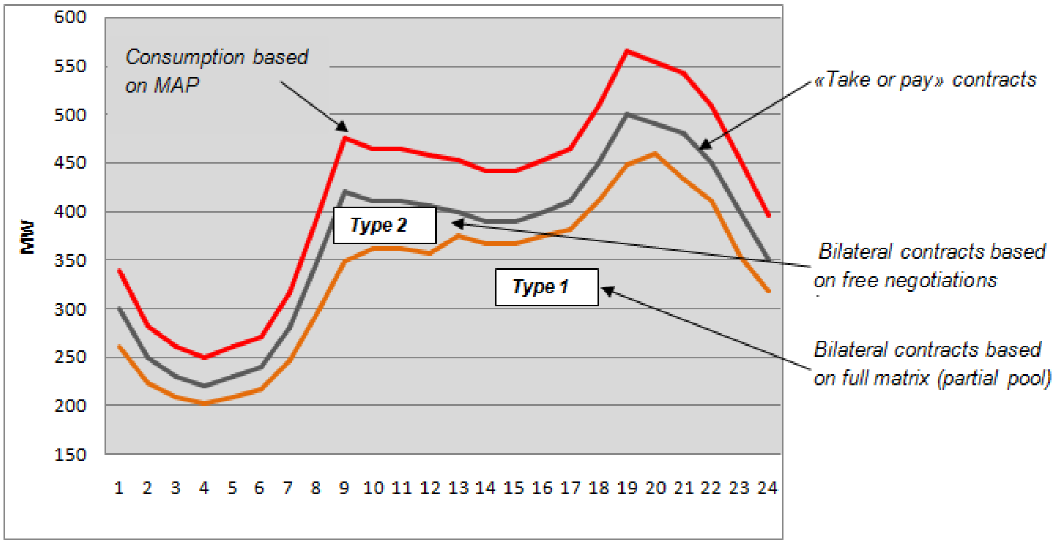
Type 2. *Free negotiations between market participants*

This type of contract corresponds to today's practice, but in the future, they should be on an hourly basis.

Monthly bi-lateral contracts are the sum of above two types of hourly contracts on monthly base.

There is a high probability that the sum of these two types of contracts will not cover 100% of planned consumption (Fig .3.1).

Fig. 3.1 Contracts on monthly basis



For price minimization the additional contracts that will cover the gap between the planning consumption and the volumes by contracts of types 1 and 2 are needed.

Such additional contracts on a daily basis are advisable to have on a daily basis since the goal is 100% covering of the DAP shape and not MAP for a particular day.

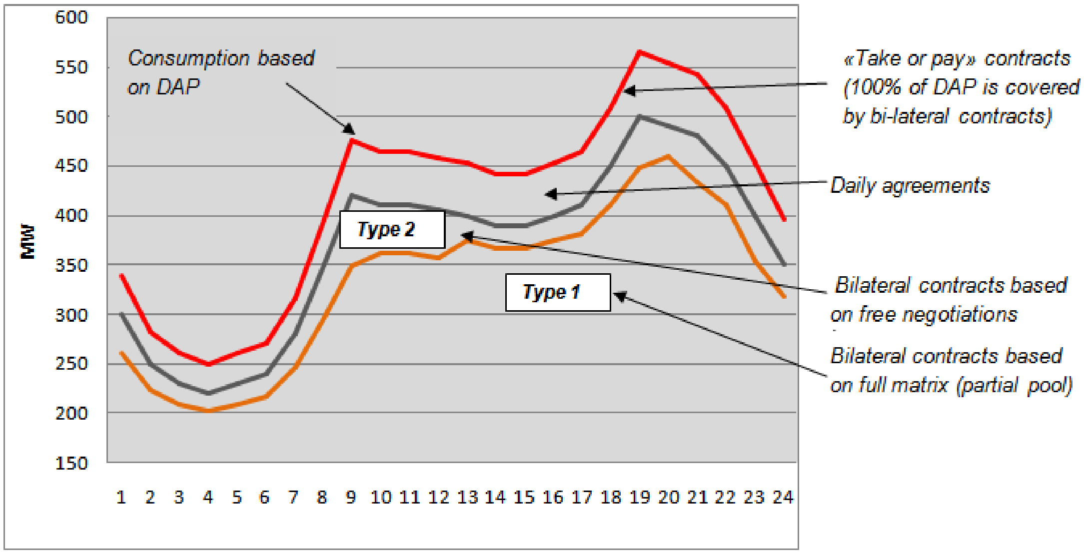
It is very important from the point of view of the contracts based on a "take or pay" principle.

As a result of discussions with ESCO this option was adopted.

In this case, there is a high probability of 100% coverage of the daily consumption through bi-lateral contracts.

Fig. 3.2 summarizes all types of contracts where instead of a MAP curve (Fig. 3.1) appears DAP curve (red line).

Fig. 3.2 Sum of contracts



Such combination of contracts on the monthly (relatively long-term) and daily basis is the optimal one.

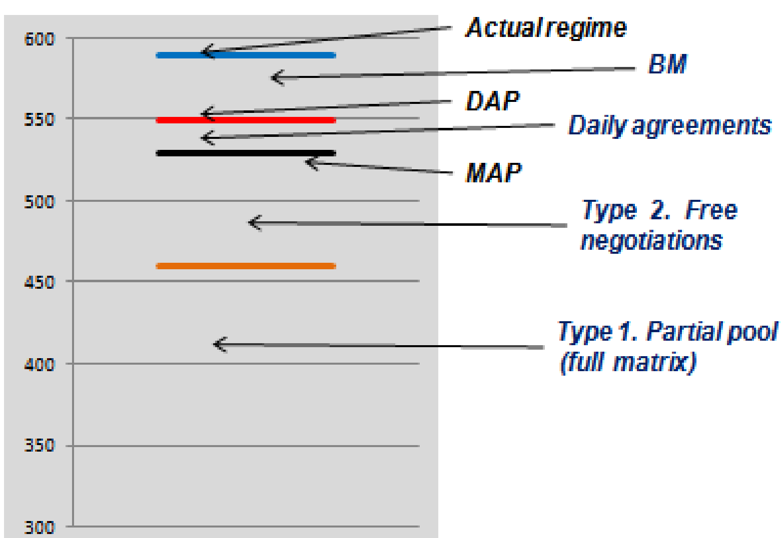
Monthly contracts allow the participant to optimize a participant's portfolio in advance.

Moreover the lack of a unified regional market will prevent conclusion of export/import contracts during the day.

The presence of the contracts on a daily basis will minimize participation in the balancing market, where prices are higher.

On Fig. 3.3 all types of contracts (100% of DAP is covered by contracts) are shown as well as balancing electricity.

Fig. 3.3 Trade sectors for each hour (100% of DAP is covered by contracts)



It is possible that contracts don't cover 100% of DAP: (1) the sum of the capacities by contracts 1 and 2 is less than MAP or/and (2) the sum of the capacities by contracts 1 and 2 and daily agreements is less than DAP.

In reality the market participants can't operate only in accordance with the signed bi-lateral contracts so deviations are inevitable even when bi-lateral contracts fully cover the DAP curve.

In any cases required balancing capacity (deviation) is the capacity of actual regime minus appropriate volume under all contracts.

4. BALANCING MECHANISM

According to GEMM 2015, the Stage1 of reform does not include the implementation of the system of bids and offers with prices, which does not allow for the possibility of the full-fledged functioning of the balancing market.

In any case, if a market participant actually acting on power market deviates from electricity volumes scheduled by bi-lateral contracts, it becomes a balancing market participant. And depending on the sign of that deviation, the Seller may become a Buyer and vice versa taking into account "take or pay" principle of contracts.

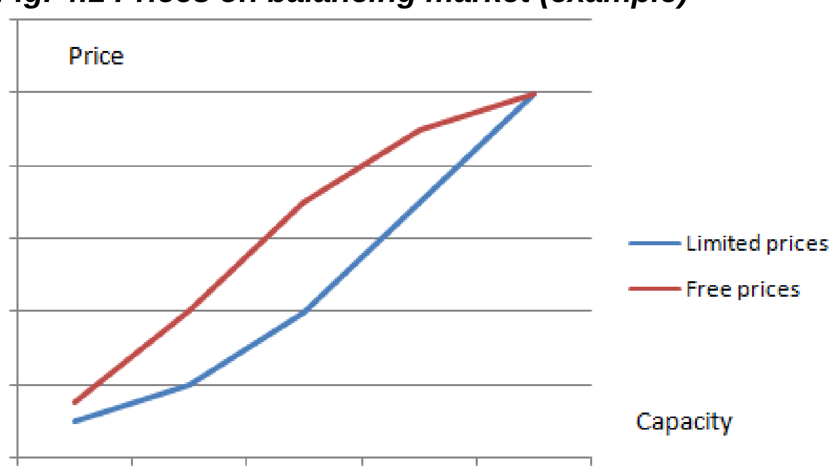
For example, the generator that produced less than the planned by bi-lateral contracts volume should purchase supplementary energy on the balancing market and the off-taker that reduced its consumption can sell the surplus.

In practice it will not be balancing market, but so-called deviations market.

The decision of a balancing mechanism without bids on the first stage is absolutely correct, because in case of lack of competition on the market, the generation price on market will rise sharply because of the generators desire to participate on balancing market instead of trading with bi-lateral contracts.

This is due to the fact that HPPs understand that with bids that are a little lower than TPPs' and import prices, they will fall into balance, especially in winter. At the same time, the price for HPPs can be significantly higher than their regulated tariff. This will result in an outcome shown in Fig. 4.1.

Fig. 4.1 Prices on balancing market (example)



Currently for each market participant, the deviation from the planned value of bi-lateral contracts (after adjustments) is provided on a monthly basis - single value.

Then average monthly balancing price is determined based on generators participation and their fixed prices on a monthly basis – single value.

ESCO bills the amount for each market participant determined by simply multiplying these two values.

The main disadvantages of this mechanism are:

- Bi-lateral contracts adjustments affecting the magnitude of the deviations;
- There is no mechanism for determining hourly deviations, which results in a significant difference between actual deviations and estimated monthly deviations;
- No mechanism exists to determine hourly prices, which actually equates deviations at night and peak;
- There is not difference in prices for small and large deviations that lead to balancing price increase.

All this allows concluding that used balancing mechanism is imperfect.

The new balancing mechanism being developed should exclude these disadvantages.

Balancing electricity (capacity) will be the difference between the actual regime and the sum of bilateral contracts concluded by hours that as mentioned above are not subject to adjustment (Fig.3.2).

Consumption deviation (balancing electricity) for consumer ***Djh*** for each hour ***h*** is defined by the following algorithm.

$$DC_{jh}= P_{ajh} – P_{bjh} / (1+L_h)$$

where DC_{jh}– consumption deviations on border of consumer j;
P_{ajh} – actual consumption for consumer j;
P_{bjh}- sum of bi-lateral contracts of consumer j;
L_h – average losses portion in p.u.

The calculations used losses because bilateral contracts enclosed in the point of generation and therefore the deviation must also be determined at this point

$$\Delta L_h= G_{ah} – G_{bh}- \sum_j DC_{jh}$$

where ΔL_h– additional actual market losses due to deviations in MW;
G_{ah} – sum of actual system generation;
G_{bh} – sum of generation by bi-lateral contracts

$$\Delta D_{jh} = \Delta L_h * DC_{jh} / \sum_j DC_{jh}$$

where ΔD_{jh}– additional losses covered by consumer j

$$D_{jh} = DC_{jh} + \Delta D_{jh}$$

The important point is to determine the degree of responsibility for each participant for each deviation (the reason, sign of the deviation), which will be expressed in an appropriate fee for the deviation for what it's necessary to develop the appropriate pricing system.

The methodology for determining prices for the balancing mechanism will be developed as part of an integrated system of pricing for the reformed Georgian market (see Section4 below).

5. PRICING

Proposed approaches are not definitive and should be the subject of serious discussion with stakeholders.

The ongoing reform should be based on the principle of "not to harm". It primarily refers to the price of generation for domestic consumers would not be any higher with this initial transition as opposed to the prices without it.

In no competition conditions (most of the year, Georgia is deficient or must use the old units at TPPs), the liberalization of prices will lead to their rapid growth. The limitation of the increase or even the decrease of prices is possible due to the competition, which is possible either in case of construction of new efficient power plants or by introducing mechanisms to limit prices.

Thus, at the first stage of the reform, such a pricing system should be designed that will limit the growth in prices.

5.1. PRICING OF BI-LATERAL CONTRACTS

5.1.1 PARTIAL POOL (TYPE 1 OF CONTRACTS)

Selected generators must participate in a partial pool with their regulated tariffs, at that the Enguri and Vardinili HPPs must sell practically all volume of electricity in this sector. Of course the spinning reserve services offered by these units must continue and not be restricted by the bi-lateral electricity sales and purchase agreements.

Taking into account that approved tariffs for existing medium-sized HPPs are also relatively low they must have the rights to address to Market Operator for participation in the partial pool, leaving to them the absolute possibility of contracting by free negotiations.

Existing small HPPs can also exercise this right, the only difference is that they have to negotiate for the price with Market Operator as their approved marginal price is quite high and in the summer this electricity may not be demanded in the domestic market.

The main incentive for investment in new power plants is the possibility of electricity sale to the Turkish market. However, it is not a fact that all new power plants will be able to sell electricity for export. Considering the need to attract investments in the construction of new power plants and the lack of feed-in tariffs, it is necessary to consider the possibility of participation of new plants in the partial pool with predetermined prices differentiable by seasons.

The consolidator(s) (proposed in 2015 GEMM) also must be able to participate in the partial pool at prices negotiated with the Market Operator. Under the existing law, only ESCO is allowed to buy from generators and resell inside Georgia.

5.1.2 MONTHLY CONTRACTS BETWEEN MARKET PARTICIPANTS BY DIRECT NEGOTIATIONS (TYP2 2 OF BI-LATERAL CONTRACTS).

This case is characterized by the absence of restrictions on the offered price, and if for some reason a consumer wants to buy additional, but more expensive electricity, the generator can sell it.

However considering that the consumer has the opportunity to purchase more electricity also on "daily" market, it is unlikely that negotiated bi-lateral contract prices will be higher than the regulated tariffs for generators.

5.1.3. DAILY AGREEMENTS (CONTRACTS).

As mentioned above this type of contract, providing to cover the difference between the DAP and the volume of bi-lateral contracts on monthly basis for a particular day,is also an element of a "planning" market..

On the "daily" market negotiated prices or the prices not exceeding regulated tariffs will be realized.

Generation price minimization can be reached by 100% coverage of planned consumption through bi-lateral contracts.

5.2. BALANCING PRICES (DEVIATIONS MARKET)

Prices on balancing trade sector will be higher than by bi-lateral contracts for the following reasons:

- A large share of participation in balancing includes more expensive generators (TPPs, import);
- Lack of sufficient surplus of relatively low-cost generation on Georgian market.

This fact is an incentive for consumers to improve the accuracy of planning and minimal participation on deviations market.

On the other hand, it may lead to a situation when generators will seek to sell more electricity on balancing market, reducing its offer on the market of bi-lateral contracts, which will lead to an increase in generation prices for domestic consumers.

Moreover, under the action of bi-lateral contracts on a "take or pay" principle, a consumer can request large volumes for bi-lateral contracts and sell surplus electricity on deviations market.

To avoid these risks certain mechanisms must be implemented:

- **Firstly**, it is necessary to determine who initiated this deviation. Namely the responsibility for the deviation determines the payment. The basic approach in setting the price for the deviation must be the principle that no additional financial burden is put on the market participant if it works on the planned schedule, or obeys the dispatcher’s command.

- **Secondly**, the introduction of commercial dispatching is necessary, when a dispatcher within the technical constraints leads generation regime in accordance with minimal costs (this solves the problem of generation re-dispatch).

  The larger a consumer deviates in the direction of increased load, the higher the balancing price on the deviation market will be.

  The desire to minimize this price in the absence of competition and pricing bids provides a basis for limiting the price of generators at the approved level. An exception can be made for new power plants, and maybe existing small HPPs for which the use of pre-defined capped prices is allowed that will be an incentive for investors.

- A possible option of the prices with a small step-up ratio used for generators (incentive for additional generation) would require imposing restrictions on the amount of electricity generated for balancing for the of these generators participation in bi-lateral contracts.
- If the consumer will plan an overestimated volume on the bi-lateral contracts market (cheaper market)in advance, and as a result will have a surplus that will be able to realize on the deviations market in order to extract additional profit, it is proposed to limit the opportunity for this consumer by allowing it to offer electricity to deviations market at price of partial pool multiplied by the reduction coefficient (e.g. 0.90-0.95).

5.3. PRICE OF MARKET LOSSES

The mechanism of bi-lateral contracts conclusion at the point of net generation based on the average percentage of losses on market adopted at this stage of the reform determines the required payment of losses as well. Extra charges are not needed.

Applied mechanism for the deviation determination (Chapter 3) includes additional losses, their allocation among consumers and they are actually charged by balancing price for each hour (included in deviation). Extra charges are not needed.

Therefore, it is needed to change tariffs methodology (losses component exception).

In case of rejection of this approach it’s necessary to develop a specific mechanism as was mentioned above.

Annex 1.

Month Ahead Planning

1. *Algorithms*

Period of planning.

According to the suggested methodologies, a month could be selected as a period of planning

Splitting by types of days

Considering the different levels of consumption by days of the week, planning should be implemented with consideration of this factor.

For example, Working Days, Saturdays, Sundays + public holidays could be selected as typical days.

It will probably make sense considering dispatchers' typical practice, to divide working days into Mondays and Tuesday-Fridays.

If necessary each day of a week could be considered as a typical day (the suggested methodology should not have limitations).

Availability of initial data

The metering database currently installed at GSE is unfortunately not completed yet but it is the only source of obtaining historical data required for these methodologies.

It is necessary that while using Alpha Center (metering database and software) the meter readings be grouped in such a manner that for each market participants one value be received by each hour (capacity).

Based on the existing information held by GSE, developing hourly electricity accounting by hour is possible and will it involve all market participants included into the metering system.

Looking ahead, we may say that the absolute values of capacities will be not used in calculations for the initial operation of MAP, but rather the shapes of daily load curves. This will allow reducing the impact of missing meters.

Thus, the MAP development and the metering system development may proceed as parallel processes.

The details of the required historical data

The number of previous years to be used in the analysis could be from one to three years.

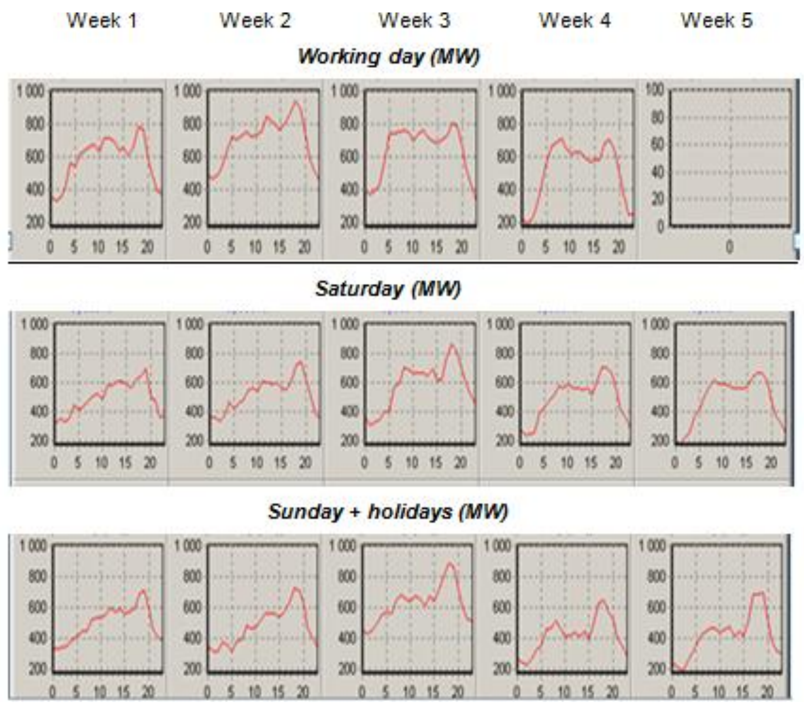
The methodology should allow varying this indicator. On one hand, the more the information, the better is the result, because more data will allow considering the difference between years, for example, different weather conditions and "water levels"; on the other hand, the closer the given year to the planning year, the more considerable it may become from the viewpoint of accuracy of the results.

The idea of the approach and the phases of planning are as follows:

Processing of historical data

At the beginning we would suggest an example, when only the past year is considered for historical data. Hypothetical data were used for illustration (figure below).

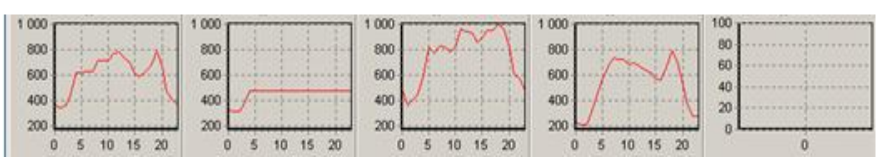
Figure A1.1. Examples of Daily Load Curves



For each typical day of the month under review, the shape of curve in per units is defined as the value of energy of a specific hour in relation to the sum of daily values of energy of all days of that type.

If any diagram falls out of the given pattern, for example, due to failure of a meter, it should be excluded from the calculation (figure Fig. A1.2). In this example the second diagram falls out and should be excluded from the analysis.

Figure A1.2 Data filtering



In this connection it is necessary that the quality of the historical information be analyzed prior to the identification of shapes of the curves.

After these steps we can obtain a shape of the curve for each type of a day of the month under review.

In the case when several years of historical data are reviewed, the forms of curves are defined for each year separately and then they are averaged.

Calculations of hourly curves for market participants for the planned period

Currently only monthly volumes of electricity are being planned for each market participant. The task is to divide this one number in MWh into each hour of the month in MW.
The main task will be to identify the weighted coefficients by each hour of the planned month.
Based on the analysis of historical data we will obtain the average weight coefficients for all types of days for each hour

$$K_{ti} = \frac{\sum_{j=1}^{n} E_{ij}}{\sum_{j=1}^{n} E_j} (1)$$

t – type of a day, t = 1, …..,f;
f – number of typical days over the historical month;
I - hour, i =1, ….,24;
n – number of t-type days over the historical month;
K_{ti}–weight coefficient for the hour i of the averaged curve of the typical day t over the historical month;
E_{ij}– volume of electricity at hour i of the j^{th} day of type t over the historical month;
E_j – volume of electricity of the j^{th} day of type t over the historical month

This does not mean that their direct application is possible for obtaining the weight coefficients by each hour of the planned month due to the following reasons:

- Different volumes of electricity for different typical days;
- Different weekly volumes (for example due to weather factor);
- Different number of typical days in the planned and retrospective months (calendar synchronization is needed).

First of all we shall calculate the relation of the electricity volume between the typical days. For this we shall calculate the aggregate electricity volume of typical days in the historical period, and then divide it into the number of days of that type. As a result we will get the average volume of electricity by each type of a day.
Then we shall define the “daily coefficients” as a ratio of the historical electricity volume of each typical day for example to the working days.

$$K_t = \frac{\sum_{j=1}^{m} E_j/m}{\sum_{j=1}^{n} E_j/n} (2)$$

K_t – daily coefficients of the relation between daily average volumes of electricity on typical days and the daily average volume over the first day type of the historical month;
t = 1, ….,f
n – number of days of first type over the historical month;
m – number of days on each type of day t over the historical month;
E_j – daily volume of electricity over the j^{th} day of the historical month

The received average historical weighted coefficients by hours shall be multiplied by daily coefficients depending on the type of a day.
This will allow considering the averaged weight coefficients the difference between energies of the typical days, for example, between a Saturday and a working day. Thus,

the weight coefficients in per unit of various types of days become reduced to one base by energy.
Note: the sum of weighted coefficients by typical days, except for the working days, will not equal to 1.
The changes of volumes by weeks should be also considered. For this reason a notion of “weekly coefficients” is used
Considering that some of typical days (e.g. Saturday) are once in a week and may not give a clear tendency of a weekly change, as a weekly coefficient the ratio of an average day for the given week to the average day of the first week can be used (historical).

$$K_l = \frac{\sum_{j=1}^{a} \mathrm{E_{jl}}/a}{\sum_{j=1}^{b} \mathrm{E_{j1}}/b} \quad (3)$$

K_l - ratio of an average day for the given week to the average day of the first week

$\mathrm{E_{jl}}$ – Daily electricity volume for l^{th} week;

a and b – number of days in l^{th} and first week respectively

How can one use the above mentioned coefficients for the planning period?
The portion of each hour in the volume of electricity for the planning month should be defined.
The product of three corresponding coefficients for each day of the planning period should then be calculated.
For example, if one assumes the first day of the planning period is Saturday, then K_{ti} corresponding to the average Saturday for 24 hours shall be selected. Then these coefficients shall be multiplied by K_t (see above) representing the ratio of the average Saturday energy to the average working day energy over the retrospective month.
Then this product shall be multiplied by a weekly coefficient K_l corresponding weekly coefficient shall be selected for planning day of month defined as a ratio of historical volume of electricity of average day of each week to 1^{th} week.
With this, all coefficients by each hour of the planning month K_h are calculated.

$$K_h = K_{ti} \times K_t \times K_l \quad (4)$$

h= 1, …….,d;
d – number of hours in the planning month.
The sum of these coefficients will not equal to the sum of days of the planning month, therefore to calculate the portion of each hour A_h in the energy of the planning month we should calculate the following:

$$A_h = \frac{K_h}{\sum_{h=1}^{d} K_h} \quad (5)$$

These received coefficients A_h are final for the planned month.
Multiplying the planned monthly volume by the A_h the planned capacities for the whole month by hours are obtained.

In case of necessity to determined different curves for working days of the week (should be discussed from the perspective of further market development in terms of direct contracting), an additional mechanism of splitting weekly volumes by days could be applied, as a result of which each working day of the week will be similar by the shape of the curve, but different by the volume.

2. Example

Let's consider as an example a consumer with daily peak consumption.

The historical hourly data on purchase of electricity are presented in Table A1.1 (one year is taken as a retrospective period).

Based on these data the averaged curves of consumption by typical days are defined (Working days, Saturdays and Sundays & public holidays are taken as typical days), represented in MW (Table A1.2) and in portions of each hour in the daily consumption by formula (1) (Table A1.3.).

Then, the daily coefficients for typical days under type 1 are defined by formula (2). The following coefficients are received: for Working days - 1.0, for Saturdays – 0.9723 and for Sundays &holidays – 0.8743.

The following values for weekly coefficients are calculated by formula (3):

1^{th}week	2^{th}week	3^{th}week	4^{th}week	5^{th}week
1.0	1.0083	0.9876	0.9722	0.9832

Then, considering the synchronization calendar for the planning month the values of K_h for each hour of the planning month are calculated by formula (4) (Table A1.4, the values are presented as K_h*10^2). The sum of all K_h in our example is 30.17. Dividing each K_h by 30.17 we receive A_h by formula (5), i.e. the weighted coefficients of each hour in the consumption of the planning month and multiplying these coefficients by the planned volume of monthly consumption (in this example it is assumed to be 22000 MWh) we receive the planning capacities by each hour (Table A1.5).

Table A1.1. Metering data of historical month in MW

Days	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
	T	We	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat	Su	Mon	T	W	Tue
00:00-01:00	26.5	26.7	26.9	26.5	26.9	25.9	25.4	26.8	26.8	27.2	26.1	27.1	25.5	25.1	26.2	25.7	26.0	26.3	27.2	25.8	25.1	26.5	26.1	25.9	25.8	26.7	24.3	23.9	26.1	25.9	26.3
01:00-02:00	24.6	24.7	25.0	24.6	25.0	24.2	23.6	24.9	24.9	25.3	24.3	24.9	23.9	23.5	24.4	23.7	24.2	24.4	25.4	24.1	23.4	24.5	24.2	24.0	24.1	24.5	22.7	22.1	23.9	23.9	24.5
02:00-03:00	23.5	23.7	23.9	23.4	23.8	22.9	22.6	23.9	24.0	24.6	23.7	23.7	22.9	23.0	23.4	23.1	23.3	23.1	24.2	22.9	22.5	23.5	23.5	23.3	23.0	23.6	20.8	21.6	23.3	23.0	23.8
03:00-04:00	23.1	23.3	23.5	23.3	23.3	22.1	22.2	23.6	23.7	24.4	23.4	23.3	22.1	22.9	23.2	22.7	23.0	22.4	23.6	22.0	22.1	23.3	23.5	23.1	23.1	23.2	20.4	0.0	23.0	22.8	23.7
04:00-05:00	23.0	23.1	23.7	22.9	23.1	22.1	22.2	23.6	23.5	24.5	23.4	23.1	22.1	22.8	23.2	22.7	22.9	22.8	23.3	22.0	22.0	23.2	23.4	23.0	23.0	23.1	20.7	21.1	22.9	22.8	23.7
05:00-06:00	23.2	23.5	23.7	23.3	23.5	22.3	22.4	23.9	24.0	24.6	23.6	23.3	22.4	22.8	23.4	22.8	23.3	23.0	23.6	21.8	22.3	23.3	23.6	23.1	23.0	23.3	20.7	21.4	23.2	23.2	23.9
06:00-07:00	23.9	24.2	24.4	23.9	23.8	22.2	23.3	24.5	24.5	25.1	23.8	23.6	22.2	23.4	23.8	23.3	23.7	23.4	23.5	21.4	22.7	23.7	24.0	23.5	23.3	23.2	20.3	21.6	23.7	23.5	24.1
07:00-08:00	25.4	25.6	26.1	25.5	24.7	22.2	25.4	26.4	26.5	26.6	25.4	24.6	22.3	25.2	25.4	24.7	25.2	25.4	24.6	21.4	24.6	25.4	25.1	25.2	25.2	24.4	20.5	23.6	25.5	25.1	25.6
08:00-09:00	29.3	29.7	30.1	29.6	28.1	23.4	29.9	30.6	30.9	30.5	29.8	27.8	23.2	29.0	29.2	28.7	29.1	29.6	27.9	23.1	29.2	29.4	29.1	29.7	29.9	27.6	22.0	28.4	30.0	29.3	29.8
09:00-10:00	31.9	32.4	32.7	32.6	31.5	25.6	33.2	33.7	33.6	33.3	32.1	30.5	25.4	32.3	31.9	31.6	31.7	32.2	30.9	25.1	32.1	32.0	31.8	32.0	32.3	30.5	23.9	31.1	32.7	31.7	31.7
10:00-11:00	32.8	33.3	33.6	33.3	32.8	27.0	34.4	34.5	34.5	34.2	33.2	31.5	26.5	33.3	33.0	32.4	32.3	32.9	31.8	26.4	32.9	32.7	32.4	32.6	32.9	31.4	25.6	32.1	33.3	32.3	32.6
11:00-12:00	33.2	33.7	34.0	33.4	33.4	27.9	35.0	34.8	34.8	34.5	33.4	32.0	27.0	33.7	33.3	32.7	32.4	32.6	32.1	27.2	33.0	32.7	32.3	32.6	33.0	31.6	26.2	32.3	33.3	32.5	32.9
12:00-13:00	32.2	32.5	32.8	32.0	32.2	27.7	33.5	33.2	33.2	32.5	31.2	30.9	26.9	32.1	31.6	31.3	30.7	30.1	30.6	26.6	31.4	31.0	30.8	31.0	30.9	30.5	25.7	30.9	31.6	30.7	31.2
13:00-14:00	32.3	32.7	32.4	32.1	32.0	27.5	33.4	33.3	33.3	32.6	31.6	30.6	26.9	32.3	31.7	31.3	30.6	30.6	30.3	26.4	31.4	31.0	30.8	31.2	31.4	30.2	25.6	30.8	31.5	30.7	31.2
14:00-15:00	32.6	32.9	32.6	32.3	31.5	27.3	33.9	33.7	33.7	32.8	31.9	30.2	26.8	32.5	31.8	31.6	30.8	30.9	30.2	25.8	31.5	31.3	31.2	31.4	31.9	29.7	25.4	30.8	31.7	31.2	31.3
15:00-16:00	32.4	32.6	32.2	32.2	31.0	27.2	33.6	33.5	33.4	32.6	31.6	29.7	26.6	32.2	31.5	31.4	30.6	30.7	29.6	25.4	31.3	31.1	30.9	31.3	31.2	28.9	25.0	30.6	31.3	30.9	30.9
16:00-17:00	32.6	32.9	32.6	32.5	31.0	27.5	33.7	33.8	33.7	32.8	32.1	29.4	27.0	32.3	31.8	31.5	30.7	30.7	29.4	25.7	31.3	31.1	30.8	31.3	31.2	28.6	24.7	30.8	31.4	30.8	30.9
17:00-18:00	33.0	33.5	32.6	33.0	31.2	28.5	34.3	34.3	34.1	33.4	32.6	29.9	27.5	32.9	32.2	31.9	31.3	31.5	29.9	27.1	31.6	31.3	31.0	31.6	31.6	29.0	25.9	31.0	31.2	30.8	30.7
18:00-19:00	33.2	33.7	33.1	33.4	32.2	30.1	34.5	34.5	34.5	34.1	33.2	31.4	29.2	33.3	32.8	32.5	32.4	32.7	31.5	29.4	32.8	32.5	32.7	32.7	32.7	30.7	27.9	31.5	31.7	30.9	30.9
19:00-20:00	32.9	32.8	32.7	32.5	31.7	30.1	33.9	33.8	33.0	33.0	32.0	30.9	29.2	32.5	32.2	32.1	32.0	32.4	31.5	29.5	32.3	32.5	32.2	32.4	32.1	31.0	28.4	31.6	32.3	31.7	31.7
20:00-21:00	32.1	32.1	31.8	32.1	31.1	29.6	33.2	33.0	32.4	32.3	31.5	30.3	28.9	31.8	31.5	31.6	31.5	31.9	30.9	29.1	31.9	31.9	31.4	31.7	31.4	30.4	28.1	31.6	32.0	31.9	31.9
21:00-22:00	31.7	31.5	31.2	31.6	30.6	29.2	33.2	32.3	31.8	31.9	30.8	30.1	28.7	31.2	31.2	31.1	30.8	31.6	30.8	29.1	31.4	31.3	30.6	31.1	30.9	29.9	28.1	30.7	31.3	31.0	31.2
22:00-23:00	31.0	31.1	30.9	31.5	30.2	28.9	32.3	31.9	31.3	31.3	30.5	29.4	28.3	30.9	30.7	30.6	30.6	31.0	30.2	28.6	31.0	30.8	30.3	30.6	30.5	29.5	27.6	30.2	31.0	30.7	30.7
23:00-24:00	29.7	30.0	30.0	30.5	29.3	27.9	31.0	30.7	30.3	30.2	29.4	28.5	27.4	29.6	29.6	29.5	29.4	29.7	29.1	27.4	29.8	29.7	29.1	29.6	29.5	28.6	26.6	29.0	29.8	29.7	29.9

Table A1.2 Capacities in MW for average historical days

Hours	Working day	Saturday	Sunday+holidays
00:00-01:00	26.1	27.0	25.4
01:00-02:00	24.2	25.0	23.7
02:00-03:00	23.3	23.8	22.3
03:00-04:00	22.1	23.4	21.6
04:00-05:00	23.0	23.2	21.7
05:00-06:00	23.2	23.4	21.8
06:00-07:00	23.7	23.5	21.6
07:00-08:00	25.4	24.6	21.6
08:00-09:00	29.6	27.9	22.9
09:00-10:00	32.3	30.8	25.0
10:00-11:00	33.1	31.9	26.4
11:00-12:00	33.3	32.3	27.1
12:00-13:00	31.7	31.0	26.7
13:00-14:00	31.8	30.8	26.6
14:00-15:00	32.0	30.4	26.3
15:00-16:00	31.7	29.8	26.1
16:00-17:00	31.9	29.6	26.2
17:00-18:00	32.2	30.0	27.3
18:00-19:00	32.9	31.5	29.1
19:00-20:00	32.5	31.3	29.3
20:00-21:00	31.9	30.7	28.9

Table A1.3 Weighted coefficients in p.u. for average historical days

Hours	Working day	Saturday	Sunday+holidays
00:00-01:00	0.0373	0.0396	0.0415
01:00-02:00	0.0346	0.0367	0.0388
02:00-03:00	0.0333	0.0350	0.0365
03:00-04:00	0.0316	0.0343	0.0353
04:00-05:00	0.0329	0.0340	0.0355
05:00-06:00	0.0332	0.0344	0.0356
06:00-07:00	0.0339	0.0346	0.0352
07:00-08:00	0.0363	0.0361	0.0353
08:00-09:00	0.0423	0.0409	0.0375
09:00-10:00	0.0461	0.0453	0.0408
10:00-11:00	0.0473	0.0468	0.0431
11:00-12:00	0.0476	0.0475	0.0443
12:00-13:00	0.0452	0.0456	0.0437
13:00-14:00	0.0454	0.0452	0.0434
14:00-15:00	0.0457	0.0446	0.0430
15:00-16:00	0.0453	0.0438	0.0426
16:00-17:00	0.0455	0.0435	0.0429
17:00-18:00	0.0460	0.0441	0.0445
18:00-19:00	0.0470	0.0462	0.0476
19:00-20:00	0.0464	0.0460	0.0478
20:00-21:00	0.0456	0.0451	0.0473

Table A1.4. Values K_h*10^2 for planning month

s	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat
00:00-01:00	3.73	3.73	3.85	3.63	3.76	3.76	3.76	3.76	3.76	3.88	3.76	3.68	3.68	3.68	3.68	3.68	3.80	3.58	3.62	3.62	3.62	3.62	3.62	3.74	3.53	3.66	3.66	3.66	3.66	3.66	3.79
01:00-02:00	3.46	3.46	3.57	3.39	3.49	3.49	3.49	3.49	3.49	3.59	3.50	3.41	3.41	3.41	3.41	3.41	3.52	3.35	3.36	3.36	3.36	3.36	3.36	3.47	3.30	3.40	3.40	3.40	3.40	3.40	3.51
02:00-03:00	3.33	3.33	3.40	3.19	3.36	3.36	3.36	3.36	3.36	3.43	3.36	3.29	3.29	3.29	3.29	3.29	3.36	3.15	3.24	3.24	3.24	3.24	3.24	3.31	3.10	3.28	3.28	3.28	3.28	3.28	3.35
03:00-04:00	3.16	3.16	3.34	3.09	3.19	3.19	3.19	3.19	3.19	3.36	3.32	3.12	3.12	3.12	3.12	3.12	3.29	3.05	3.07	3.07	3.07	3.07	3.07	3.24	3.00	3.11	3.11	3.11	3.11	3.11	3.28
04:00-05:00	3.29	3.29	3.31	3.10	3.31	3.31	3.31	3.31	3.31	3.33	3.31	3.25	3.25	3.25	3.25	3.25	3.27	3.07	3.20	3.20	3.20	3.20	3.20	3.22	3.02	3.23	3.23	3.23	3.23	3.23	3.25
05:00-06:00	3.32	3.32	3.35	3.11	3.35	3.35	3.35	3.35	3.35	3.38	3.34	3.28	3.28	3.28	3.28	3.28	3.31	3.07	3.23	3.23	3.23	3.23	3.23	3.26	3.02	3.26	3.26	3.26	3.26	3.26	3.29
06:00-07:00	3.39	3.39	3.36	3.08	3.42	3.42	3.42	3.42	3.42	3.39	3.43	3.35	3.35	3.35	3.35	3.35	3.32	3.04	3.29	3.29	3.29	3.29	3.29	3.27	2.99	3.33	3.33	3.33	3.33	3.33	3.30
07:00-08:00	3.63	3.63	3.51	3.08	3.66	3.66	3.66	3.66	3.66	3.54	3.67	3.58	3.58	3.58	3.58	3.58	3.47	3.04	3.53	3.53	3.53	3.53	3.53	3.41	3.00	3.57	3.57	3.57	3.57	3.57	3.45
08:00-09:00	4.23	4.23	3.98	3.27	4.26	4.26	4.26	4.26	4.26	4.01	4.26	4.17	4.17	4.17	4.17	4.17	3.93	3.23	4.11	4.11	4.11	4.11	4.11	3.87	3.18	4.16	4.16	4.16	4.16	4.16	3.91
09:00-10:00	4.61	4.61	4.41	3.57	4.65	4.65	4.65	4.65	4.65	4.44	4.66	4.55	4.55	4.55	4.55	4.55	4.35	3.52	4.48	4.48	4.48	4.48	4.48	4.28	3.47	4.53	4.53	4.53	4.53	4.53	4.33
10:00-11:00	4.73	4.73	4.55	3.77	4.77	4.77	4.77	4.77	4.77	4.59	4.79	4.67	4.67	4.67	4.67	4.67	4.49	3.72	4.60	4.60	4.60	4.60	4.60	4.42	3.66	4.65	4.65	4.65	4.65	4.65	4.47
11:00-12:00	4.76	4.76	4.62	3.87	4.80	4.80	4.80	4.80	4.80	4.65	4.83	4.70	4.70	4.70	4.70	4.70	4.56	3.82	4.62	4.62	4.62	4.62	4.62	4.49	3.76	4.68	4.68	4.68	4.68	4.68	4.54
12:00-13:00	4.52	4.52	4.43	3.82	4.56	4.56	4.56	4.56	4.56	4.47	4.62	4.47	4.47	4.47	4.47	4.47	4.38	3.77	4.40	4.40	4.40	4.40	4.40	4.31	3.71	4.45	4.45	4.45	4.45	4.45	4.36
13:00-14:00	4.54	4.54	4.39	3.80	4.57	4.57	4.57	4.57	4.57	4.43	4.63	4.48	4.48	4.48	4.48	4.48	4.34	3.75	4.41	4.41	4.41	4.41	4.41	4.27	3.69	4.46	4.46	4.46	4.46	4.46	4.32
14:00-15:00	4.57	4.57	4.34	3.76	4.61	4.61	4.61	4.61	4.61	4.37	4.67	4.52	4.52	4.52	4.52	4.52	4.28	3.71	4.45	4.45	4.45	4.45	4.45	4.22	3.65	4.50	4.50	4.50	4.50	4.50	4.27
15:00-16:00	4.53	4.53	4.26	3.72	4.57	4.57	4.57	4.57	4.57	4.29	4.63	4.48	4.48	4.48	4.48	4.48	4.21	3.68	4.41	4.41	4.41	4.41	4.41	4.14	3.62	4.46	4.46	4.46	4.46	4.46	4.19
16:00-17:00	4.55	4.55	4.23	3.75	4.59	4.59	4.59	4.59	4.59	4.26	4.68	4.50	4.50	4.50	4.50	4.50	4.17	3.70	4.43	4.43	4.43	4.43	4.43	4.11	3.64	4.48	4.48	4.48	4.48	4.48	4.16
17:00-18:00	4.60	4.60	4.28	3.89	4.64	4.64	4.64	4.64	4.64	4.32	4.74	4.55	4.55	4.55	4.55	4.55	4.23	3.84	4.48	4.48	4.48	4.48	4.48	4.17	3.78	4.53	4.53	4.53	4.53	4.53	4.21
18:00-19:00	4.70	4.70	4.49	4.16	4.74	4.74	4.74	4.74	4.74	4.53	4.79	4.64	4.64	4.64	4.64	4.64	4.44	4.11	4.57	4.57	4.57	4.57	4.57	4.37	4.05	4.62	4.62	4.62	4.62	4.62	4.42
19:00-20:00	4.64	4.64	4.47	4.18	4.68	4.68	4.68	4.68	4.68	4.51	4.67	4.58	4.58	4.58	4.58	4.58	4.41	4.13	4.51	4.51	4.51	4.51	4.51	4.35	4.07	4.56	4.56	4.56	4.56	4.56	4.39
20:00-21:00	4.56	4.56	4.38	4.13	4.60	4.60	4.60	4.60	4.60	4.42	4.58	4.50	4.50	4.50	4.50	4.50	4.33	4.08	4.43	4.43	4.43	4.43	4.43	4.26	4.02	4.48	4.48	4.48	4.48	4.48	4.31
21:00-22:00	4.48	4.48	4.33	4.11	4.52	4.52	4.52	4.52	4.52	4.37	4.51	4.43	4.43	4.43	4.43	4.43	4.28	4.06	4.36	4.36	4.36	4.36	4.36	4.21	3.99	4.41	4.41	4.41	4.41	4.41	4.26
22:00-23:00	4.42	4.42	4.26	4.05	4.46	4.46	4.46	4.46	4.46	4.30	4.44	4.36	4.36	4.36	4.36	4.36	4.21	4.00	4.30	4.30	4.30	4.30	4.30	4.14	3.94	4.34	4.34	4.34	4.34	4.34	4.19
23:00-24:00	4.26	4.26	4.13	3.90	4.29	4.29	4.29	4.29	4.29	4.16	4.28	4.21	4.21	4.21	4.21	4.21	4.07	3.86	4.14	4.14	4.14	4.14	4.14	4.01	3.80	4.19	4.19	4.19	4.19	4.19	4.06

Table A1.5 Capacities for planning month in MW

Days	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat	Su	Mon	T	W	Tue	Fri	Sat
00:00-01:00	27.2	27.2	28.1	26.4	27.4	27.4	27.4	27.4	27.4	28.3	27.4	26.8	26.8	26.8	26.8	26.8	27.7	26.1	26.4	26.4	26.4	26.4	26.4	27.3	25.7	26.7	26.7	26.7	26.7	26.7	27.6
01:00-02:00	25.2	25.2	26.0	24.7	25.4	25.4	25.4	25.4	25.4	26.2	25.5	24.9	24.9	24.9	24.9	24.9	25.7	24.4	24.5	24.5	24.5	24.5	24.5	25.3	24.0	24.8	24.8	24.8	24.8	24.8	25.6
02:00-03:00	24.3	24.3	24.8	23.3	24.5	24.5	24.5	24.5	24.5	25.0	24.5	24.0	24.0	24.0	24.0	24.0	24.5	23.0	23.6	23.6	23.6	23.6	23.6	24.1	22.6	23.9	23.9	23.9	23.9	23.9	24.4
03:00-04:00	23.1	23.1	24.3	22.5	23.3	23.3	23.3	23.3	23.3	24.5	24.2	22.8	22.8	22.8	22.8	22.8	24.0	22.2	22.4	22.4	22.4	22.4	22.4	23.6	21.9	22.7	22.7	22.7	22.7	22.7	23.9
04:00-05:00	24.0	24.0	24.1	22.6	24.2	24.2	24.2	24.2	24.2	24.3	24.1	23.7	23.7	23.7	23.7	23.7	23.8	22.4	23.3	23.3	23.3	23.3	23.3	23.4	22.0	23.6	23.6	23.6	23.6	23.6	23.7
05:00-06:00	24.2	24.2	24.4	22.7	24.4	24.4	24.4	24.4	24.4	24.6	24.4	23.9	23.9	23.9	23.9	23.9	24.1	22.4	23.5	23.5	23.5	23.5	23.5	23.7	22.1	23.8	23.8	23.8	23.8	23.8	24.0
06:00-07:00	24.7	24.7	24.5	22.4	24.9	24.9	24.9	24.9	24.9	24.7	25.0	24.4	24.4	24.4	24.4	24.4	24.2	22.2	24.0	24.0	24.0	24.0	24.0	23.8	21.8	24.3	24.3	24.3	24.3	24.3	24.1
07:00-08:00	26.4	26.4	25.6	22.5	26.7	26.7	26.7	26.7	26.7	25.8	26.8	26.1	26.1	26.1	26.1	26.1	25.3	22.2	25.7	25.7	25.7	25.7	25.7	24.9	21.9	26.0	26.0	26.0	26.0	26.0	25.2
08:00-09:00	30.8	30.8	29.0	23.9	31.1	31.1	31.1	31.1	31.1	29.3	31.1	30.4	30.4	30.4	30.4	30.4	28.7	23.6	30.0	30.0	30.0	30.0	30.0	28.2	23.2	30.3	30.3	30.3	30.3	30.3	28.5
09:00-10:00	33.6	33.6	32.1	26.0	33.9	33.9	33.9	33.9	33.9	32.4	33.9	33.2	33.2	33.2	33.2	33.2	31.7	25.7	32.7	32.7	32.7	32.7	32.7	31.2	25.3	33.1	33.1	33.1	33.1	33.1	31.6
10:00-11:00	34.5	34.5	33.2	27.5	34.8	34.8	34.8	34.8	34.8	33.5	34.9	34.1	34.1	34.1	34.1	34.1	32.8	27.1	33.5	33.5	33.5	33.5	33.5	32.3	26.7	33.9	33.9	33.9	33.9	33.9	32.6
11:00-12:00	34.7	34.7	33.6	28.2	35.0	35.0	35.0	35.0	35.0	33.9	35.2	34.3	34.3	34.3	34.3	34.3	33.2	27.9	33.7	33.7	33.7	33.7	33.7	32.7	27.4	34.1	34.1	34.1	34.1	34.1	33.1
12:00-13:00	33.0	33.0	32.3	27.8	33.3	33.3	33.3	33.3	33.3	32.6	33.7	32.6	32.6	32.6	32.6	32.6	31.9	27.5	32.1	32.1	32.1	32.1	32.1	31.4	27.1	32.4	32.4	32.4	32.4	32.4	31.8
13:00-14:00	33.1	33.1	32.0	27.7	33.3	33.3	33.3	33.3	33.3	32.3	33.7	32.7	32.7	32.7	32.7	32.7	31.6	27.4	32.1	32.1	32.1	32.1	32.1	31.1	26.9	32.5	32.5	32.5	32.5	32.5	31.5
14:00-15:00	33.3	33.3	31.6	27.4	33.6	33.6	33.6	33.6	33.6	31.9	34.1	32.9	32.9	32.9	32.9	32.9	31.2	27.1	32.4	32.4	32.4	32.4	32.4	30.8	26.6	32.8	32.8	32.8	32.8	32.8	31.1
15:00-16:00	33.0	33.0	31.0	27.1	33.3	33.3	33.3	33.3	33.3	31.3	33.8	32.6	32.6	32.6	32.6	32.6	30.7	26.8	32.1	32.1	32.1	32.1	32.1	30.2	26.4	32.5	32.5	32.5	32.5	32.5	30.5
16:00-17:00	33.2	33.2	30.8	27.3	33.5	33.5	33.5	33.5	33.5	31.1	34.1	32.8	32.8	32.8	32.8	32.8	30.4	27.0	32.3	32.3	32.3	32.3	32.3	30.0	26.6	32.6	32.6	32.6	32.6	32.6	30.3
17:00-18:00	33.6	33.6	31.2	28.4	33.8	33.8	33.8	33.8	33.8	31.5	34.6	33.2	33.2	33.2	33.2	33.2	30.8	28.0	32.6	32.6	32.6	32.6	32.6	30.4	27.6	33.0	33.0	33.0	33.0	33.0	30.7
18:00-19:00	34.2	34.2	32.8	30.3	34.5	34.5	34.5	34.5	34.5	33.0	34.9	33.8	33.8	33.8	33.8	33.8	32.4	30.0	33.3	33.3	33.3	33.3	33.3	31.9	29.5	33.7	33.7	33.7	33.7	33.7	32.2
19:00-20:00	33.8	33.8	32.6	30.5	34.1	34.1	34.1	34.1	34.1	32.9	34.1	33.4	33.4	33.4	33.4	33.4	32.2	30.1	32.9	32.9	32.9	32.9	32.9	31.7	29.6	33.2	33.2	33.2	33.2	33.2	32.0
20:00-21:00	33.3	33.3	31.9	30.1	33.5	33.5	33.5	33.5	33.5	32.2	33.4	32.8	32.8	32.8	32.8	32.8	31.6	29.8	32.3	32.3	32.3	32.3	32.3	31.1	29.3	32.7	32.7	32.7	32.7	32.7	31.4
21:00-22:00	32.7	32.7	31.6	30.0	32.9	32.9	32.9	32.9	32.9	31.9	32.9	32.3	32.3	32.3	32.3	32.3	31.2	29.6	31.8	31.8	31.8	31.8	31.8	30.7	29.1	32.1	32.1	32.1	32.1	32.1	31.1
22:00-23:00	32.2	32.2	31.1	29.5	32.5	32.5	32.5	32.5	32.5	31.3	32.4	31.8	31.8	31.8	31.8	31.8	30.7	29.2	31.3	31.3	31.3	31.3	31.3	30.2	28.7	31.7	31.7	31.7	31.7	31.7	30.6
23:00-24:00	31.1	31.1	30.1	28.5	31.3	31.3	31.3	31.3	31.3	30.3	31.2	30.7	30.7	30.7	30.7	30.7	29.7	28.1	30.2	30.2	30.2	30.2	30.2	29.2	27.7	30.5	30.5	30.5	30.5	30.5	29.6

Annex 2

Electricity Losses Allocation on Georgian Electricity Market

A2.1. Background

The new model of the Georgian electricity market implies a transition to hourly settlements and will initially (Stage 1) operate on model of bilateral contracts and a balancing mechanism.

Bilateral contracts should be concluded at least for one month duration and based on Month Ahead Planning (MAP) concept (see Part 1 of this report).

It should be noted that the responsibility borders of competitive market participants in Georgia may be the connection points to either transmission or distribution networks.

Thus, in this report, the electricity losses will be understood exactly as losses in the network for the competitive electricity market, rather than the losses in the transmission or distribution networks. On ESCO's website these losses are defined as transportation expenses.

Here we will use the term competitive market losses or losses. The task lies in the fair allocation of these losses.

The approach to fair losses allocation should be guided both by technical and price aspects that requires the need for a comprehensive approach.

First consider physical approach for determining losses on the market, the contribution of each consumer in losses creation and the portion of each generator in their coverage.

A2.2. Physical method for losses allocation and structural analysis.

For each hour of a planned month based on MAP data, the load flow calculations will be performed by GSE using PSS/E software.

In Fig.A2.1 the results of calculations for a hypothetical 5-node system for one hour are presented.

After load flow calculation by special mechanisms[1,2] the following parameters are defined (Table A2.1):

P_{ij} -consumption portion of j^{th} consumer from i^{th} generator,

ΔP_{ij} -active capacity losses due to P_{ij},

$P_{ij} + \Delta P_{ij}$ -generation portion of i^{th} plant to j^{th} consumer,

[1]V. Safaryan. "Structural Analysis of Power Flows and Losses in Electrical Circuits". Proceedings of the Academy of Sciences of Republic of Armenia, TN 2001,

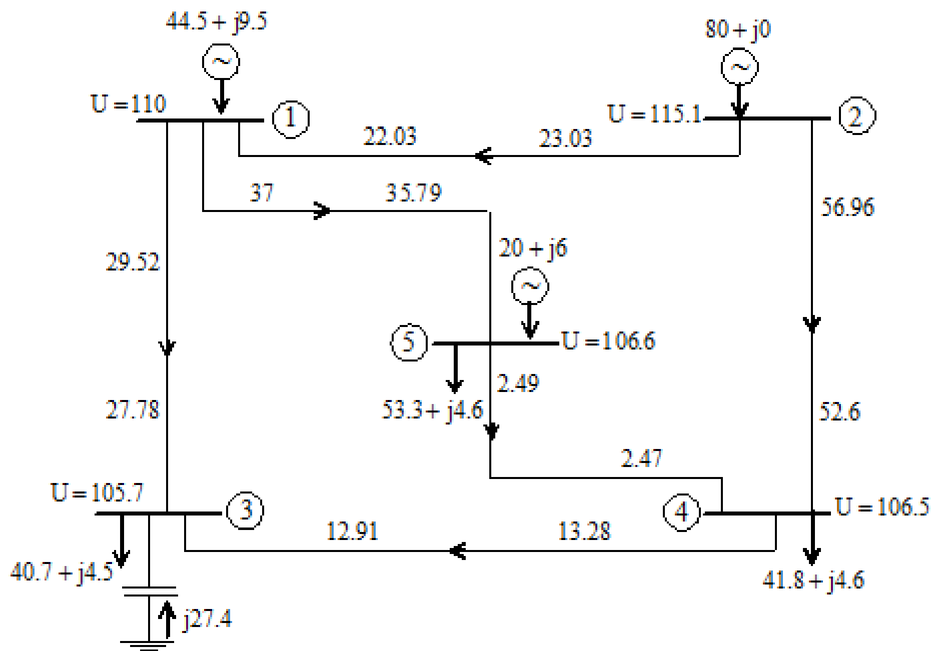
[2]V. Safaryan. "Analysis of Directions of Flows of Active Capacity of Electric Circuits". CJSC "Institute of Energy". Yerevan, 2001-8p

$\Delta P_i = \sum_j \Delta P_{ij}$ -losses covered by i[ith] generator,

$\Delta P_j = \sum_i \Delta P_{ij}$ -losses created by j[th] consumer,

$\Delta P = \sum_i \Delta P_i = \sum_j \Delta P_j$ -losses in network.

Fig.A2.1. Load flow calculations results (Option 1)



The following conditions are satisfied

$P_i = \sum_j (P_{ij} + \Delta P_{ij})$ -active capacity of i[th] generator,

$P_j = \sum_i P_{ij}$ -active capacity of j[th] consumer,

$\sum_i P_i = \sum_j P_j + \Delta P$ - Active capacity balance.

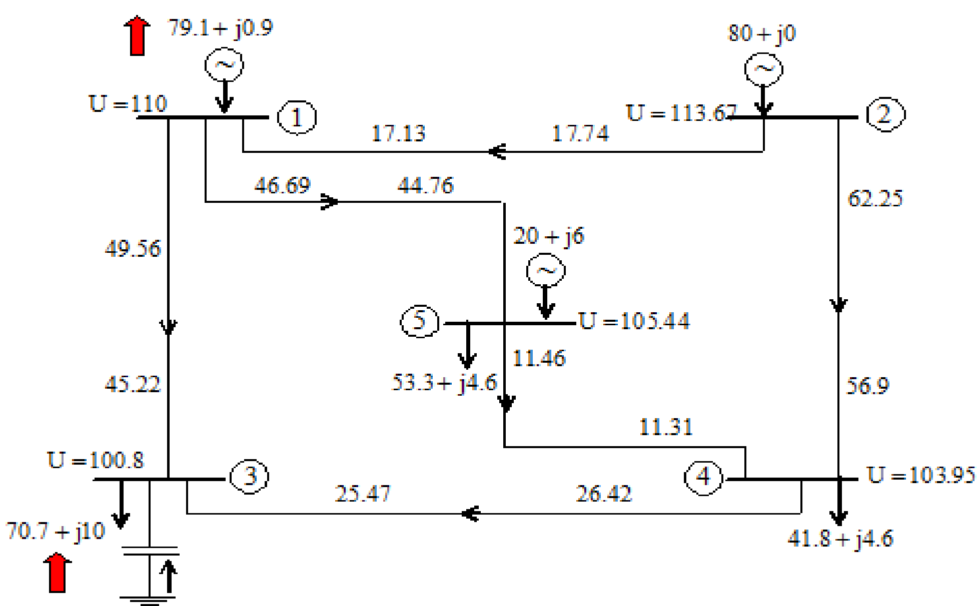
Table A2.1 Structural analysis results (Option 1)

			Consumers			Losses covered by generators
			bus3	bus4	bus5	
			40.7	**41.8**	**53.3**	
Generators	bus1	**44.501**	18.835	0.806	22.869	**1.991**
	bus2	**80**	21.657	40.321	11.323	**6.699**
	bus5	**20**	0.208	0.673	19.108	**0.011**
Losses created by consumers			**3.628**	**3.380**	**1.694**	**8.701**

A2.3. Disadvantages to use physical method for fair allocation of market losses in Georgia

1. As can be seen from the Table A2.1,the structure of the grid has a great impact on the losses created. So although the Load 5 is the biggest, it creates fewer losses due to proximity to Generator 5 despite the fact that its capacity is small. At the same time the Generator 5 does not take part in covering system losses.
2. The influence of one wholesale consumer on others also is a disadvantage. This is seen from the results shown on Fig. A2.2. The difference with above regime is the load increasing in Node 3 only (generation in Node 1 is increased too).

Fig.A2.2. Load flow calculations results (Option 2)



As seen from Table A2.2, the portions of losses created by all consumers are increasing.

Table A2.2 Structural analysis results (Option 1)

			Consumers			Losses covered by generators
			bus3	bus4	bus5	
			70.7	**41.8**	**53.3**	
Generators	bus1	**79.1**	39.57	3.93	30.28	**5.32**
	bus2	**80**	29.82	35.72	6.56	**7.9**
	bus5	**20**	1.3	2.14	16.46	**0.1**
	Losses created by consumers		**7.89**	**3.6**	**1.83**	**13.32**

What does this mean in terms of the competitive market?

Suppose that a competitive electricity market participant operates on the market in accordance with the planned indicators and pays its portion of the losses calculated in accordance with the planned dispatch regime on the market. Another participant whose actual deliveries or receipts from the market deviates from the planned dispatch regime, results in a change of losses. In compliance with the principle of fairness, only this participant should be responsible for the loss deviation (by the physical method that would not happen).

3. As seen from Tables A2.1 and A2.2, there is a different mix of generators in covering losses. Therefore the price of losses is different too for these regimes. With load increasing, it's possible this price growth taking into account the involvement in the balance less efficient generators or more import.

4. In accordance with MAP (DAP) concept it's necessary initially to determine value Net generation minus Losses for each generator to conclude bilateral contracts. If you make calculations at the end of the month the losses covered by the generator can be different in comparison with planned regimes.

A2.4. Proposed mechanism for losses allocation for Georgian electricity market

The description below is the essence of the proposed approach in relation to the Phase 1 (GEMM 2015) of the reform of the Georgian electricity market, namely the operation on the basis of bilateral contracts and hourly balancing mechanism.

Note that in the future when implementing Day Ahead Market (DAM) two types of deviations (for the DAM and the balancing market) will be calculated with a decrease in portion through bilateral contracts.

Proposed mechanism consists of two steps:

- Loss allocation for planned regimes for coming month based on MAP shapes;

➢ Additional losses allocation due to deviations and market participants responsibility at the end of the month based on actual regime analysis.

All of the below-mentioned considerations are given for one hour.

Not to complicate the text, let's imagine that the above mentioned Option 1 afterwards will regard to planned regime and the Option 2 is for the actual one.

***Step 1**Planning losses for coming month allocation by hours*

1. Hourly losses calculation for competitive electricity market based on Month Ahead Planning shapes;

2. Calculation of losses covered by each generator based on structural analysis (physical method) - ΔP_i (see paragraph A2.2);

3. Volume of losses to be paid by each consumer (domestic, trader, etc.) determination in proportion of consumption (see Table 4.3).

$$\Delta C_j = \frac{\sum_i \Delta P_i}{\sum_j C_j} * C_j$$

Proposed approach removes disadvantages 1 (historical structure of the Georgian power system), 3 (possible different losses price for consumers),4 (the need to taking into account losses in advance) and partially 2 (consumption of one consumer impact to others) mentioned in paragraph A2.3.

Table A2.3 Losses allocation by physical and proposed methods for Option 1 in MWh

	Bus 3	Bus 4	Bus 5
Physical method	3.628	3.380	1.694
Proposed (step 1)	2.607	2.678	3.415

For using the proposed approach the calculations of hourly planning regimes (reactive power of load must be estimate too) are required.

To avoid these calculations (if any difficulties occur) it's possible to use simplified approach, namely, taking into account loss allocation in proportion with consumption, it's possible to use average percentage for system losses for each consumer based on historical data (Table A2.4).

Table A2.4 Historical calculated losses (transportation expenses) on Georgian electricity market in % (ESCO's data)

	Jan	*Feb*	*Mar*	*Apr*	*May*	*Jun*	*Jul*	*Aug*	*Sep*	*Oct*	*Nov*	*Dec*	*Year*
2010	*1.85*	*1.59*	*1.58*	*1.56*	*1.60*	*1.90*	*1.69*	*2.12*	*1.87*	*1.74*	*1.60*	*1.64*	***1.73***
2011	*2.13*	*2.22*	*1.61*	*1.68*	*1.61*	*1.84*	*1.88*	*2.17*	*1.95*	*1.68*	*2.11*	*1.74*	***1.89***
2012	*1.70*	*1.87*	*1.93*	*1.67*	*1.83*	*1.74*	*1.86*	*1.78*	*1.59*	*1.75*	*1.81*	*1.72*	***1.77***

For this approach the following formula can be used

$$\Delta Cj = Losses\ \%/100 * \sum_i Pi * \frac{Cj}{\sum_j Cj}$$

Where P_i – net generation of i^{th} generator based on MAP (DAP),

C_j – consumption of j^{th} wholesale consumer based on MAP (DAP),

Losses% - average competitive market losses level in %.

This approach doesn't require hourly preliminary load flow calculations, but the hourly detailed analysis of historical regimes is needed.

Both options of proposed mechanism can be implemented for planning regime only.

Step 2*Additional losses allocation due to actual and planning regimes deviations*

Step 2 is provided because the deviations between actual and planning regimes of participants are unavoidable.

1. At the end of the month, the TSO carries out the calculation of hourly losses based on actual regime and according to the method of structural analysis determines the values of the losses created by each consumer and covered by each generator (physical method).

2. Deviation of each consumer is determined as

$$D_j = A_j - C_j$$

3. Difference in losses between actual and planning regimes (A, G – actual and planned consumption and generation correspondingly)

$$D_{losses} = \sum_i (G_i - P_i) - \sum_j (A_j - C_j)$$

4. Finally the losses to be paid by each consumer are calculated based on Step 1 and additional losses allocation in proportion with participant's deviations

$$L_j = \Delta C_j + D_{losses} * D_j / \sum_j D_j$$

For above example, the final losses allocation is presented in Table A2.5.

Table A2.5 Proposed losses allocation for above example in MWh

	Bus 3	Bus 4	Bus 5
Physical method for actual regime	7.89	3.60	1.83
Physical method for planned regime	3.63	3.38	1.69
Deviations by physical method	4.26	0.22	0.14
Losses for planned regime by proposed method	2.61	2.68	3.42
Deviations by proposed method	4.62	0	0
Losses to be paid	7.23	2.68	3.42

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