The new electricity market arrangements in Cyprus

Note that **the official Version** of this Document, forming part of CERA's Regulatory Decision 01/2015, **is in Greek language**. The English translation is given for information purposes only. In case of any inconsistency or conflict, the official, Greek version applies.

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1. Structure of the Report

Subject Report describes a proposed set of arrangements and regulatory interventions required for the operation of a competitive electricity market in Cyprus.

The Report is organised in 13 Sections accompanied by two Annexes. The background and scope of this Report are presented in Section 2. Section 3 provides an introduction to the main market segments as well as to the various market participants and parties and to their respective roles in the market. Section 4 presents the operation of a forward market which is organised on a bilateral (over the counter) basis. Section 5 presents details on how the day- ahead market will be organised while section 7 presents the arrangements proposed for securing and procuring adequate operating reserves within the frame of an Integrated Scheduling Process. Section 8 presents the organisation of the real time Balancing Mechanism, while Section 9 presents the approach for the final settlement of market participants. Section 10 discusses the way the market is organised in respect of RES plants operation distinguishing the arrangements between RES pants operating under National Grant Plans and RES plants operating outside any support scheme. Section 11 presents the wholesale transactions of the main market participants with the Market Operator. Section 12 presents a set of various other arrangements required for a smooth market operation, including security cover requirements, metering profiling provisions, losses management, emergency arrangements etc. Finally the report under Section 13 briefly discusses the way Demand Response could be accommodated in the proposed market design in the future.

Within Section 6, a high level choice is made regarding the regulatory framework for RES output curtailments. The proposal is for RES output to be curtailed only for system security reasons and upon this high level choice the design of the market has been developed.

The Report is accompanied by two Annexes. Definitions of terms (exclusively for the purposes of subject report) are presented in Annex A. Annex B provides for a description of the Block Generating Orders.

2. Scope of the Report and Background

Cyprus Energy Regulatory Authority (CERA), following a technical support project that had been carried out the previous months regarding market reorganisation, concluded on the Net Pool model as being the most appropriate trading arrangement approach for the Cyprus electricity market. The formulation of a net pool as proposed by the LDK- E-Bridge study incorporates both, a central Day Ahead Market compatible with the Price Coupling of Regions (PCR) algorithm, and an Intra-Day Market. A forward market is also envisaged to provide participants with risk management tools. The proposed design is supplemented with a) an Integrated Scheduling Process along with a real time Balancing Mechanism which provide the TSO with the ability to procure and activate balancing services and b) a settlement process. .

Following the above high level decision of CERA, the Support Group for Cyprus (SGCY) assigned a technical assistance contract to support CERA and the Ministry of Energy, Commerce, Industry and Tourism (MECIT) to design and approve a net pool policy for the electricity market as per the above high level structure.

Subject document comprises the outcome of the above technical assistance. The work focuses on providing CERA, the TSO/MO and the market stakeholders with enough guidance and operational details with regard to the envisaged structure and settlements to be performed under a net pool scheme.

Under subject report the proposed final arrangements, based on the above high level approach, develop a set of regulatory arrangements per market segment aiming at creating an appropriate market environment for market participants to activate in the electricity sector of Cyprus. It is however underlined that proposed arrangements include substantial regulatory intervention as, due to the current 100% concentration of the market, these arrangements are initially trying to mimic a competitive environment with a view to gradually enforcing it.

The proposed design allows bilateral, over the counter, contracting on a forward basis while at the day-ahead stage a central market is organized. CERA should regulate the minimum participation of the Dominant Participant in the DAM with a view to enforcing adequate liquidity.

Specifically, under the proposed net pool design, bilateral physical forward contracts are notified and corresponding schedules are nominated to the Market Operator (MO) by OTC market gate closure on the day ahead. Suppliers and generators provide bid curves to a Day Ahead Market (DAM) on a half hourly basis. Orders in the DAM are unit based in the case of generators[1]. Suppliers submit orders based on individually forecast demand. Orders in the DAM should correspond to quantities not already covered by bilateral contracts and take into account any Replacement Reserve of type 2 commitments. The DAM is centrally managed by a Market Operator (MO).

[1] or per RES plant or per RES aggregator

The MO runs a process of matching bid curves to optimise dispatch of residual volumes at the day ahead. Contracts resulting from the DAM are between market participants and the MO at the DAM clearing price. An Integrated Scheduling Process with a real time Balancing Mechanism and later a continuous intra-day trading platform will be organized to further support market operations.

3. Introduction to the market

3.1 Market Segments

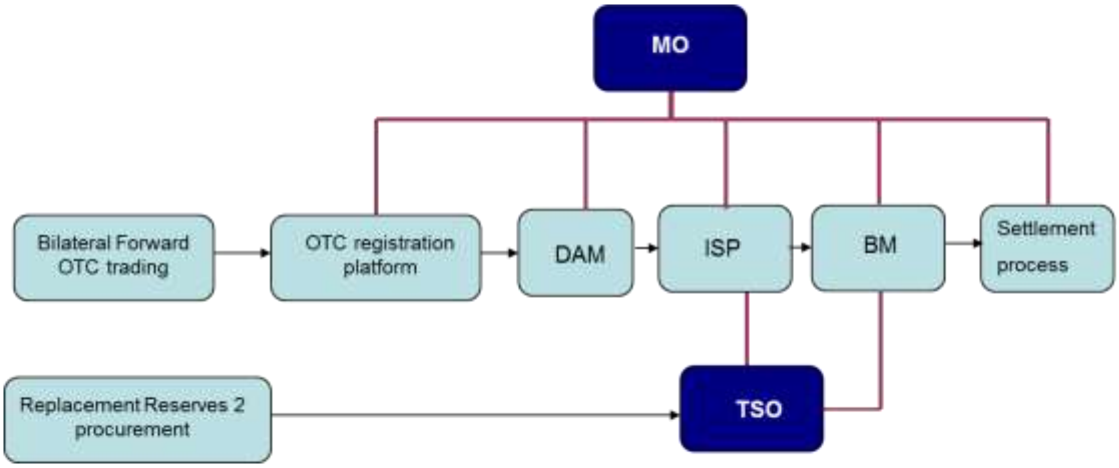

Figure 1- Main Net Pool market processes in Cyprus

The main new elements introduced under the proposed new arrangements relate to the operation of a centrally managed Day Ahead Market (DAM) through which licensed participants may buy and sell energy to supplement any bilateral contracts they have entered to and the subsequently application of an integrated scheduling process. Participation to the DAM for the residual quantities (i.e. quantities that have not been contracted at the forward stage or contracted as Replacement Reserve of type 2) is mandatory for all generating units. The DAM is a market whereas energy products with physical delivery are traded, meaning that only participants with physical injection and offtake points can submit orders to this market.

With a view to fostering liquidity in the DAM, especially with regard to RES absorption, CERA should require [X] percentage of the country's consumption needs to be covered through the DAM[2].

The current 100% concentration of the Cyprus market constitutes a major issue which has been taken into account when designing all segments of the new wholesale market. In this respect, and with a view to avoiding placing barriers to the entry of new suppliers, the above obligation will be initially placed only to the Dominant Participant's supply volumes[3]. As competition

[2] CERA is examining the possibility of enforcing a percentage ranging between 10 and 20% (indicative figures)

[3] For purposes of practical application of the above mentioned obligation in cases of third suppliers' activation in the market, a corresponding methodology will be developed to determine corresponding details

emerges, CERA will examine the possibility for introducing relevant obligations to the supply volumes of those independent suppliers who have gained a considerable market share.

RES under the National Grants' Plans (NGPs) will continue to participate into the market through EAC. Though, at a later stage, CERA may shift corresponding responsibility to other suppliers as well.

New RES plants operating outside NGPs may either contract on a bilateral basis at the forward stage or bid into the DAM pool as per the detailed provisions under Section 10. RES plants operating outside any support scheme with installed capacity above 1 MW may either directly participate (per plant) into the market arrangements or through an aggregator. An upper limit determined by CERA is introduced to the aggregated quantities. Direct participation to the market involves forecasting responsibilities per plant.

RES plants operating outside any support scheme with installed capacity lower than 1 MW may only participate through an aggregator. In either case (either individually or through an aggregator) corresponding operators should take care to install adequate metering facilities that will allow for at least half-hourly metering of their output.

Apart from the bilateral transactions and the DAM, an integrated scheduling process is operated by the TSO in order to schedule generating units and dispatchable load and procure most types of operating reserves. The TSO also runs a balancing process with a view to purchasing and selling energy quantities to balance the system in real time. All market participants should carry balance responsibility towards the MO in accordance with the detailed rules provided under Section 9, with the exemption of RES plants under NGPs, on behalf of which EAC carries corresponding responsibility.

Participation to the integrated scheduling process and to the real time Balancing Mechanism by all thermal units with installed capacity above [5] MW[4] is mandatory . Load holding appropriate capabilities (Dispatchable Load) may participate to balancing services' provision (including both balancing reserves and balancing energy provision).

RES plant operators (as well as RES aggregators) which hold appropriate technical capabilities and equipment (in accordance with the specifications and criteria as set by the TSO) allowing them to follow TSO's dispatch orders may participate offering downwards balancing energy from the beginning of market operation. RES plants participation to the Balancing Mechanism should be initiated on equal terms and obligations compared to those applied to conventional units and dispatchable load. Obviously this requires that the RES plants hold appropriate technical equipment that will allow the process to treat them under the same arrangements.

The operation of the DAM and later the introduction of an Intra-Day Market makes ex-post conclusion of energy contracts less important. Ex-post conclusion of energy contracts is an option to offer market participants less exposure to imbalances and has been utilised in the past

[4] See footnote number 9 regarding the obligations and rights of conventional units below [5] MW.

in Norway (known as ex-post contracts notification), however it requires a certain level of portfolio management capabilities otherwise it could be considered as providing for a more favourable environment for the Dominant Participant. Based on this observation, ex-post conclusion of energy contracts is not foreseen under the new market arrangements.

In general, at the wholesale level all transactions are envisaged to take place at non-regulated prices. For the Dominant Participant though, an ex-post regulation of the prices it offers to the wholesale market will apply, as described in more details later in the document.

The proposed market design should apply from the beginning of the market and at a second phase, the MO should develop and operate an Intra- Day Market (IDM). The design of the IDM falls out of the scope of this report.

Figure 1 above presents the proposed market structure under a net pool scheme.

3.2 Determination of the Dominant Participant

Currently, EAC holds 100% of the supply market in Cyprus while it covers 92.5%[5] of the electricity produced in the country. The Electricity Law in Cyprus makes reference to the term "dominant position". Market Participants can be declared as holding a dominant position in the electricity market if they satisfy the conditions specified in the Competition Protection Law. In accordance with this law an undertaking is holding a "dominant position" when the undertaking enjoys an economic power which makes it capable of preventing efficient competition in the market and allows it to act, on a substantial degree, independently of its competitors and ultimately independently of customers. This issue has to be clarified and explicitly declared by CERA in co-ordination with the MECIT, specifically for the electricity market, before the new Market Rules are finalised.

The Net Pool design for Cyprus foresees the Dominant Participant (or the Participant holding Dominant Position depending on the final term to be officially adopted) being assigned the following tasks:

- Offer bilateral forward products under regulated terms
- purchase the energy produced by RES plants under NGPs and be responsible for the settlement of corresponding quantities through the various market segments
- mandatorily trade specific portion of its consumption volumes through the DAM (the corresponding quantities are calculated on the basis of the percentage [X] of the national demand regulated by CERA to be covered through the DAM)
- place bids[6] and offers to the DAM and the BM within a regulated range; and
- carry the Last Resort function (at least during an initial period).

[5] The remaining 7.5% is covered by RES as per the TSO of Cyprus statistical data for the year 2013
[6] It is clarified that bids for generating units means generation reduction whereas for suppliers means demand increase

3.3 Wholesale supply

The Electricity Law defines "supply" function as both sale to end customers and resale at the wholesale level. The Law also requires that supply to end eligible and end non-eligible customers (i.e. supply at retail level) requires a license. For suppliers who only intend to be active at the wholesale level the Law does not require, neither forbids, licensing. Therefore, the licensing regulation issued by CERA should:

- remove the obligation for suppliers to own sufficient generation capacity
- allow suppliers to also sell energy at the wholesale market; and
- determine whether wholesale suppliers (i.e. suppliers with no intention to enter the retail business) need a supply license or not.

Suppliers without offtake accounts (i.e. without physical absorption points-direct consumers) will have to notify their energy contracts (volumes) to the MO to allow it to follow the trading arrangements' chain between generation and final consumption points in case of mismatches and disputes.

Therefore, wholesale suppliers will have to be bound by the Market Rules[7]. The existing market rules define as market participants only those suppliers that have been granted a license for end customers' consumption. This provision should be updated within the New Market Rules to also include wholesale suppliers. It is further suggested that wholesale suppliers are licensed entities. The Cyprus market is an immature market and CERA will need to closely monitor all market participants through the imposition of appropriate licensing terms. Furthermore, wholesale suppliers should be licenced to participate in cross border trading when an interconnection is implemented.

Licensing requirements for wholesalers should reflect the intention of interested applicants to activate only at the wholesale level and therefore CERA may introduce more relaxed requirements (compared to the retail supply license requirements) as to the applicant entity's solvency. The licensing terms should further allow for cross-border trading.

It is further suggested that generation license holders are allowed to activate at the wholesale level (i.e. they are allowed to buy and resell energy quantities) therefore a corresponding term allowing them to buy and resell energy quantities at the wholesale level should be added within their generation licenses. If such a term is not added within their generation licenses, corresponding entities will have to apply for a wholesale supply license if they wish to buy and resell energy.

It is further clarified that a retail supply license should, by default, entail rights for the holder to activate at the wholesale level.

[7] This is a measure to protect new entrants in an immature market. Theoretically, there is no need for the MO to follow the wholesale exchanges. It should be each market participant's responsibility to secure the source and injection points by the time the contract is exercised.

3.4 Parties to the Market Rules

This paragraph sets out the relationship between the Parties, and their primary roles in the Market. All Parties will hold a license issued by CERA appropriate to their role in the Market. Parties may accede to the Market Rules in more than one capacity.

The following Parties should accede to the Market Rules in order to participate in the new electricity market arrangements:

- The Transmission System Operator of Cyprus (TSO)
- The Market Operator of Cyprus (MO)
- The Distribution System Operator (DSO)
- Generators with:
  - Thermal Generating Units connected to the Transmission System; or
  - Thermal Generating Units connected to the Distribution System with a nominal installed capacity greater than five [5][8] MW; or
  - RES Power Production Sites operating outside NGPs
- Aggregators of RES plants operating outside NGPs (a threshold of [20] MW will apply on RES plants aggregation)
- Retail suppliers
- Wholesale suppliers
- Balance Responsible Parties (BRPs)

Apart from the TSO, the MO and the DSO all other Parties are collectively referred to as Market Participants.

The Parties, and their respective roles in the Market, are the following:

- **Transmission System Operator (TSO):** its main tasks include the operation of the transmission system and the physical balancing of the system under the terms of the Transmission and Distribution Rules. As far as it concerns the market operation, the TSO carries the responsibility to submit transmission system meter readings for settlement purposes. The TSO is also responsible to forecast load and RES output at national level, check feasibility of scheduling, manage network constraints and procure balancing

[8] It is clarified that in case of a large number of conventional units, below [5] MW and larger than [1] MW, which are connected to the same injection point at the transmission or the distribution network and cumulatively exceed [5] MW, an obligation to participate to the wholesale markets (i.e. the forward and/or the day-ahead market) applies. In such cases, the design, for the purposes of the forward and the day-ahead markets, considers this generation as originating from one virtual conventional unit. Participation in balancing energy provision, in such cases, is optional and under the condition that the TSO has tested the response capabilities in real time, for each individual unit. Such units are not allowed to offer balancing reserve. Isolated conventional units up to [5] MW and any combination of units including units below [1] MW should be reported as negative load, under bilateral contracts with suppliers. The negative load approach for small conventional units is adopted as these units will not have the means to participate in the market.

energy and ancillary services from, and on behalf of, market participants. The TSO can therefore levy Market Participants charges for network and system operation services (following CERA's approval). This entity is legally distinct from the transmission owner. The TSO shall not own generating capacity or trade in energy for profit. The TSO should publish all information relevant to the system operation as per the EU Regulation 543/2013 and report data under the provisions of the Regulation on Wholesale Energy Markets Integrity and Transparency known as REMIT. The TSO should hold and manage its own accounts with a view to performing above responsibilities.

- **Market Operator (MO):** The MO would be a licensed entity responsible for the operation and settlement activities of the centrally managed markets i.e. the DAM and later the IDM. The roles of the TSO and MO could be carried out by the same commercial entity but this need not be necessarily the case. The MO function, as provided under the Law, is assigned to the Cyprus TSO and therefore, should be strictly monitored by CERA with a view to securing independency from the incumbent**.** Accession to the Market Rules would be a license requirement. The MO will be responsible for the registration of all bilateral, Over the Counter (OTC), forward contracts between Market Participants, including the reception of technical declarations and nominations which will then be passed to the TSO. The MO will be responsible for the operation and settlement of the DAM. It further undertakes the financial settlement following the integrated scheduling process and the real time balancing mechanism as well as the imbalance and other market uplift settlements. The MO will act as the central counterparty for the financial settlements between market participants (with the exemption of OTC contracts which will be financially settled on a bilateral basis). Information publication requirements will be applied to the MO with a view to allowing smooth operation in the market. The MO shall not own generating capacity or trade in energy for profit. The MO should hold and manage its own accounts with a view to performing above responsibilities and report data in accordance with REMIT.

- **Distribution System Operator (DSO)**: its main tasks include the operation of the distribution system under the terms of the Transmission and Distribution Rules. The DSO will undertake to inform the MO on the meter readings required for settlement purposes and shall undertake to perform the profiling calculations and submit them to the MO for market settlement purposes. The DSO may outsource metering certification services. The DSO shall not trade in energy or own generating capacity. The DSO needs no account for settlements under the Market Rules[9].

- **Thermal Generators**: Thermal generators with nominal installed capacity above [5] MW should notify any bilateral energy contracts they hold to the MO, submit declarations of their technical data, nominate physical delivery on a day-ahead basis, submit orders to the DAM, submit balancing reserve and balancing energy offers and hold appropriate accounts for the purposes of the settlements performed by the MO.

[9] At a later stage when Demand Response arrangements are incorporated in the DAM and in the BM (see section 13) the DSO should directly participate in the wholesale arrangements and therefore should hold appropriate accounts.

- **RES plants[10] operators operating outside NGPs:** RES plants operators operating outside NGPs with installed capacity above [1] MW have the possibility to either participate through an aggregator or individually. In the latter case, RES operators should notify any bilateral energy contracts they hold, per plant, to the MO, submit declarations of their technical data, forecast and nominate generation scheduling on a day-ahead basis, submit orders to the DAM, and hold appropriate accounts for the purposes of the settlements performed by the MO.

- **Aggregator of RES plants:** Aggregators of RES plants operating outside NGPs for an aggregated size of RES plants from [1] MW up to [20] MW each, should notify the MO of any bilateral energy contracts they hold on a cumulative basis, submit declarations of the technical data of the RES power plants they represent, forecast and nominate physical delivery on a day-ahead basis on a cumulative basis, submit orders to the DAM on a cumulative basis, and hold appropriate accounts for the purposes of the settlements performed by the MO.

- **Retail Suppliers**: retail suppliers should notify their bilateral energy contracts to the MO, submit meter representation declarations, nominate on a day-ahead basis their offtake quantities, place orders to the DAM and balancing energy and reserve offers for the dispatchable load they represent (such offers are optional) and hold appropriate accounts for the purposes of the settlements performed by the MO.

- **Wholesale Suppliers:** wholesale suppliers should notify[11] their bilateral energy contracts to the MO up to D-2. Wholesale suppliers need no account under the Market Rules.

- **Balance Responsible Parties: BRPs** are entities that undertake the financial settlement towards the MO with regard to the imbalances registered for a group of market participants as provided under para 9.4.

3.5 Admission to the Market

Market Participants wishing admission by the MO must submit a Participation Application accompanied by a signed Participation Agreement; in the Agreement, the contracting party (Market Participant) must state that he/she is aware of and accepts the Market Rules.

Upon admission, the applicant acquires the status of Market Participant. The MO should create and maintain a Market Participants Registry.

The market will be managed through an information system to which participants will have access through the Internet. Access to the information system is based on personal identification of users-participants.

[10] It is clarified that for the purposes of this Report a high efficiency cogeneration plant is considered to form a category of RES plant

[11] notification does not mean registration in the OTC platform

Admission of the MO and the TSO as well as the obligations of the DSO should be directly ruled through corresponding licensing terms. Alternatively, if no such terms are added to the licenses of those parties, these Operators should sign a Conventional Framework Agreement of the Market Rules which should be accepted by all other participants through the Participation Agreement that the latter will be asked to sign.

As mentioned in paragraph 3.4 small (less than [1] MW) conventional units are not directly involved in the market, but declared as negative load. In this context, CERA will control the total production capacity of conventional units reported as negative load and will take appropriate action in the event that the total size of it is likely to cause market distortions.

3.6 TSO independence and capacity

The form and extent of the operational and budgetary autonomy of the TSO from EAC, prescribed by the Law, appears limited. In accordance with Article 68 of the Law, TSO revenues collected through tariffs and charges are assigned to EAC, in order to cover its own expenses as owner of the transmission system, and also the expenses of the TSO, in accordance with its budget. This provision constitutes a serious barrier regarding TSO's independence and should be modified to allow for the MO to directly collect all regulated charges as described in section 11 and then redistribute them accordingly.

According to Article 44 of the Directive 72/2009, "Article 9 of the Directive shall not apply to Cyprus". Cyprus is therefore explicitly exempted from the obligation to implement unbundling of its transmission system operator.

The Law does include provisions requiring the TSO and TSO personnel to act independently of the interests of any other licensee, especially so of EAC as a producer and supplier. However, although reasonable given the relevant exemptions from related requirements of the Directive, the above provisions of the Law do not include such strong measures as the ones prescribed by the Directive, namely:

- certification of the TSO by both CERA and the Commission[12];
- establishment of a Supervisory Body and;
- implementation of a compliance program monitored by a compliance officer appointed by the Supervisory Body, subject to approval by the regulatory authority[13].

As the TSO under the Law provisions is also assigned the role of the MO, the TSO acting as the MO will be the recipient of market data from market participants (i.e. orders to the DAM as well as offers data to the integrated scheduling process, technical availability declarations, etc.). It becomes evident that the TSO needs to carry severe restrictions as to its relationship with EAC with a view to allowing a truly independent operation of the market.

[12] Article 13 of the Directive, and Article 3 of Regulation 714/2009.
[13] Article 21 of the Directive.

Moreover, the TSO in its MO role will act as the central counterparty for a series of transactions including:

- the volumes traded in the DAM
- balancing services (i.e. balancing energy and operating reserves) cash flows
- imbalances settlement and other uplifts cash flows
- network charges collection; and
- RES fee, PSOs and other levies collection.

In such case significant financial risks and obligations are assigned to it which implies that the Cyprus TSO should be given appropriate capacity, tools and funding to address them.

Market participants should sign a Participation Agreement with the MO
Wholesale supply should be a licensed activity
Wholesale suppliers to be awarded the right to trade through interconnections
Generators to be allowed to trade at the wholesale level
Wholesale suppliers that are not serving retail customers may be subject to "lighter" solvency requirements compared to retail suppliers
As the Law assigns the TSO the MO role, its independency should be secured and adequate capacity, tools and funding should be assigned to it

4. Forward Market

4.1 Bilateral trading

Forward trading will be carried out on a wholly bilateral basis. For the time being, as it is rather unlike that sufficient volumes will exist to warrant the establishment of a dedicated central platform for forward contracts, trading is expected to take place Over the Counter (OTC).

In time though, it might prove useful that a central platform for forward products' trading, is created. However, it is clarified that the present market design includes only OTC forward transactions.

The presence of a Dominant Participant in the market indicates that the vast majority of physical energy will be traded OTC. During the first years of market operation, CERA with a view to enhancing liquidity in the forward market and enhancing independent participants' capabilities to hedge their positions, may impose the Dominant Participant in electricity generation specific terms and regulated prices with regard to its forward bilateral contracts with third parties.

CERA should periodically review the mechanism under which specific forward products will be made available to third parties. Obligation to offer specific products on a proportional basis and at regulated prices, auctions with regulated starting price or other similar mechanisms could be employed by CERA. The application of such mechanisms, which entail regulatory intervention, is a process that runs in parallel to the proposed market arrangements and should be designed to be compatible with it.

4.2 Types of Bilateral contracts

Bilateral OTC contracts by the time registered with the MO should refer to physical products. This means that corresponding contracts should refer to specific obligations for electricity quantities injection-withdrawal.

Bilateral contracts may be traded, at the wholesale level, as options up to D-1 when they are either exercised or collapse. The MO should be capable for registering a variety of different bilateral contracts (base load, peak load etc.) making sure these are matched for the corresponding half-hours (delivery periods) and counted to both the generator's and the supplier's accounts.

The financial arrangements and corresponding security covers are handled bilaterally and the MO is not involved. The contracting process may occur either directly or through brokers, the latter usually undertaking to provide mainly for the financial security between counterparties, in exchange of a service fee.

The option of allowing bilateral OTC contracts to be also financially covered through the MO of Cyprus (as the case is in the Italian forward market whereas the GME, the Italian Market Operator, is undertaking the corresponding financial risks) is not proposed in this case as the financial risk imposed to the Cyprus MO should be the minimum, considering that the MO most probably will be a new entity (either within the TSO or not) with no corresponding financial risk management background. In case the MO function is assigned to an entity with adequate financial risk management capabilities then the OTC bilateral contracts may also be financially covered through it.

4.3 Contracts Registration, Physical Delivery and Physical Offtake Nominations and Validation

The MO should operate a platform where all market participants having traded electricity quantities on a bilateral basis will manually register corresponding quantities for all half-hourly periods of each trading day.

The platform will be open for quantities registration year ahead and shall close at 9:00 EET on D-1 for the quantities corresponding to the 48 half-hours of day D.

Up to hour 13:00 on D-2 contracts may be registered either on a portfolio or on a per unit basis and per supplier either wholesale or retail supplier (counterparty). From this point onwards and up to the gate closure of 9:00 EET on D-1, registration should be made declaring the exact generating injection point (per unit or per plant in case of RES or per RES aggregator) and the retail supplier offtaking corresponding quantities. The most updated registration made by 9:00 EET on D-1 is considered as the Physical Delivery Nomination of corresponding generating units and as the Physical Offtake Nomination of corresponding retail suppliers.

It is clarified that those generators having registered quantities on a portfolio basis should submit Physical Delivery Nominations on a per unit basis (or per RES plant or per RES aggregator) the latest by 9:00 EET on D-1. This is also the gate closure for Physical Offtake Nominations.

The platform at this point should check whether Physical Delivery and Physical Offtake Nominations are matched. Furthermore, at this point the MO checks whether the Physical Delivery Nomination respects each unit's maximum capabilities (taking into account the capacity that should be left free in cases of signed Replacement Reserve type 2 contracts, as well as any other capacity restrictions e.g. weather dependent or maintenance scheduling etc.).

Each market participant (either generator or retail supplier) registering quantities for any half-hour period has to declare who the counterparty is. In case of more than one counterparties, separate registrations should take place for the same half-hour.

On D-1 by 9:15 EET, those generators and retail suppliers having registered bilaterally traded quantities should receive either:

- a confirmation that the register transaction is valid or
- an inconsistency notification.

In case of mismatches and inconsistencies, both the generator and the retail supplier are allowed to resubmit corrected and matching Nominations up to 10:00 EET. If they fail to do so until 10:00 EET on D-1 then corresponding nominations are validated up to the matched quantities meaning both counterparties are receiving a message that the mismatch quantity (actually declared by the one party) is not finally registered as bilaterally traded.

The latest by 10:30 EET, the MO should have completed corresponding validation process and issued appropriate confirmation and/or rejection tickets.

It is clarified that the Physical Delivery Nominations submitted by a generation unit is allowed to violate the technical minimum of the unit as the integrated scheduling process that follows will take care of units' commitment.

The above approach allowing Physical Delivery Nominations to violate the technical minimum (i.e. to correspond to lower traded quantities) has been adopted with a view to enabling new players to enter into forward contracts with added flexibility and in addition exploit synergies with DAM participation since the technical minimum constraints can be dealt with under the integrated scheduling process that follows the DAM closure.

It is also clarified that generation units participating in the market should arrange the physical delivery of their units in accordance with the Dispatch Orders issued by the TSO under the integrated scheduling process and the real time balancing. These orders are expected to be different from the validated Physical Delivery Nominations.

Forward market organised through OTC transactions
Later, a central platform for physical forward trading may be created
OTC contracts are settled outside the MO
CERA to regulate the dominant participant in electricity generation OTC contracts with third parties, at least for an initial period
Forward products with physical delivery are registered with a Platform operated by the Market Operator
Registration takes place per retail supplier (Physical Offtake Nomination) by hour 9:00 EET of D-1
Registration takes place per unit or per RES plant or per RES aggregator (Physical Delivery Nomination) by hour 9:00 EET of D-1

Matched Physical Offtake Nominations with Physical Delivery Nominations
Resubmission process is foreseen for non-matching Nominations up to hour 10:00 EET D-1
Physical Delivery Nominations are subject to maximum generation availability checks taking into consideration any contracted type 2 replacement reserve quantities

5. Day Ahead Market

5.1 The Day Ahead Market arrangements

The Day-Ahead Market (DAM) is organised as a wholesale electricity market, where half-hourly blocks of electricity are negotiated for the next day.

The Day Ahead Market is organised separately to the Forward market and participation to the one does not require nor oblige participation to the other. The DAM is designed to enable participants, if they wish to, to fine tune[14] the physical nominations registered earlier at the close of the OTC registration platform with quantities traded on a day-ahead basis, so as to better manage their final positions. **Within the DAM, orders for energy injection are submitted separately to orders for energy offtake**. This comprises a basic design choice. There are markets where participants have the possibility to trade on a portfolio (rather on a unit) basis. Considering the existence of a dominant player in the Cypriot system the portfolio based approach is rejected and instead the market is proposed to be organized on a unit basis and separately for supply and demand.

Based on the above, Orders for energy injection should be submitted per generating unit (or per RES plant or per RES aggregator) while orders for energy absorption are submitted per retail supplier. Participation to the DAM is possible for market participants with physical injection/absorption points.

Market participants owning generating units are obliged to offer all their available capacity (i.e. capacity that has not been nominated at the OTC registration platform or contracted under type 2 replacement reserve contracts) **in the DAM**.

RES operating outside National Grants Plans (NGPs) may participate in the DAM by placing priced offers.

Market participants wishing to schedule physical offtake may either do so by utilizing the Physical Offtake Nominations at the OTC registration platform or by utilizing the subsequent DAM, or both[15]. As the Cyprus system suffers no congestion, it is proposed that the DAM (as well as the Integrated Scheduling process and the real time balancing) treats the total of the system as one zone.

The DAM opens at 10:30 EET on D-1 (i.e. the day before the day of delivery) and closes at 13:00 EET on D-1.

[14] This approach resembles the arrangements within Italy (where an integrated scheduling process is also applied) and UK (no integrated scheduling process is applied) where the OTC contracts dominate trading and is quite different to the Nordic approach where most of the trading takes place in the spot pool market.
[15] For the Dominant Participant's supply arm a mandatory participation in the DAM is proposed with a view to creating some form of liquidity.

The MO publishes the market results and notifies the individual market results to participants and to the TSO by 13:45 EET on D-1.

All parties that have acquired the status of Market Participant may trade in the DAM. The MO acts as the central counterparty for the purchase and sale transactions concluded in the DAM.

Market Participants should submit technical declarations regarding the availability and other technical parameters of their generating units or RES plants (or major offtake points' capability) to the MO copied to the TSO for each day. They should also bear the responsibility to immediately inform the TSO and MO of any change in their availability (or major offtake capability).

The DAM trading platform and the OTC registration platform (and later the Intra-day platform) may be executed by the same or different software systems. Considering that both operations will be assigned to the same body i.e. the MO and that there will be a significant amount of data to be transmitted from the one system to the another it makes sense that a single software platform is developed accommodating all above mentioned transactions.

Electricity transactions concluded in the DAM bring economic results for generators and suppliers which are determined at the time of the DAM clearance and are directly settled with corresponding participants.

It is clarified that the energy quantities that should be injected by generation units are determined later through the integrated scheduling and real time balancing processes.

5.2 Day Ahead Market Interface with the Forward Market

The MO before accepting a generating unit's offer in the DAM should check whether this offer respects the maximum availability of the unit (taking into consideration the validated physical delivery nominations at the OTC registration platform as well as any contracted type 2 replacement reserve obligations, or any other capacity restrictions e.g. weather dependent or maintenance scheduling etc).

There is no need for the OTC quantities validated under Physical Delivery Nominations and Physical Offtake Nominations to pass through the DAM (as priority quantities i.e. as quantities that they are settled by default). The system in Cyprus is treated in one zone while physical delivery is secured under the integrated scheduling process.

5.3 Day Ahead Market Interface with the Integrated Scheduling Process and the real time Balancing Mechanism

Following DAM closure, the MO should submit to the TSO the Final Positions of market participants.

The Final Position of a generating unit is the sum of its validated Physical Delivery Nominations and its accepted Generating Orders in the DAM for every half-hour of the next day.

The Final Position of an offtaker is the sum of its validated Physical Offtake Nominations and its accepted Demand Orders in the DAM for every half-hour of the next day.

The integrated scheduling process will start taking into account the commercial programme of the generation units as these are formed on the basis of the quantities declared on the forward market platform and those cleared under the day-ahead market. For this reason the ISP process will be implemented for each day D separately. The ISP process and the algorithm implementing it should include transparent and non-discriminatory rules to ensure that the commercial programme of the generation units stemming from the forward and the day-ahead markets would be amended only to:

a) meet specific and justified technical constraints (such as units' technical minima[16]) and

b) implement the procurement of operating reserves (FCR, FRR and RR1 upwards and downwards) based on the most economic offers in both energy and reserves availability (co-optimization).

Any modification of the parameters entering the ISP algorithm violating the above rules should be recorded and justified by the TSO. Details about the ISP process are described in Section 7.

Participants' commercial programmes as reported to the TSO by the MO in the form of final positions, comprise the reference point against which imbalances are calculated taking into account the dispatch orders issued by the TSO within the frame of the ISP and the subsequent amendment of dispatch orders under real time balancing. The dispatch orders issued by the TSO do not constitute imbalance.

5.4 Day Ahead Market Interface with the Intra Day Market

The design of an Intra-Day market falls out of the scope of this report. However, it is expected that after the market has begun its operation, intra-day trading will be required by market participants with a view to minimizing their exposure to imbalances. In any case intra-day trading should be possible the latest within 24 months from the date the market starts operation under the new arrangements.

The Intra-day market should operate in a way that allows generating units and offtakers to reschedule their positions by selling and buying energy quantities to an intra-day platform.

[16] The exhaustive, and not only an indicative, list of the technical constraints under which the ISP will be performed should be determined by the TSO during Market Rules development and should be approved by CERA.

The re-scheduled positions, after validated under the intra-day trading processes, should be communicated to the TSO to take them into account during any ISP processes that follow the IDM and during the real time balancing.

It is therefore proposed that the information system will be developed in a way to allow interfaces with intra-day trading (first in sessions and then depending on the final decisions that are still pending at the EU level, intra-day maybe reshaped to a continuous trading process).

5.5 Cross border trading (price coupling)

As Cyprus is an isolated system, no arrangements are foreseen for cross border trading at any stage of the market (forward, day ahead, intra-day or real time).

However, as the MO and/or the TSO of Cyprus are about to develop appropriate market information systems, the Cyprus State should decide whether these should foresee arrangements for cross-border trading (in view of Cyprus electricity system interconnection with the Greek one or with third countries).

Considering that both Greece and Cyprus are EU member states the provisions of the Target model should be implemented with regard to cross border trading, as these are applied under the ENTSO-E Network Codes on Capacity Allocation and Congestion Management (CACM NC), the Electricity Balancing (EB NC) and the Forward Capacity Allocation (FCA NC). The design under these codes is quite advanced (however not finalized in some cases) and therefore the market arrangements foreseen for Cyprus will have to be accordingly adapted.

Based on the fact that CERA has decided to directly and quickly move to the net pool design, consideration should be given to the time implications cross border arrangements will bring, especially with regard to software and corresponding interfaces implementation and development. It is therefore suggested that the market should be implemented first without any software implementation for cross border arrangements. This means that the corresponding software cost will be born later, by the time the interconnection is implemented, when the TSO and the MO will have to adapt their information systems accordingly. However, the current status of the TSO, the lack of any previous experience in interconnections' trading as well as the market implementation timing restrictions, advocate in favor of leaving corresponding software development for a later stage.

5.6 Type of Generating and Demand Orders in the DAM

When the DAM opens i.e. at 9:30 D-1, participants may submit orders where they specify the volume and the minimum price at which they are willing to sell energy, or the volume and the maximum price at which they are willing to buy energy.

Generating Orders (offers) must be consistent with the injection capabilities of the generating units to which they refer and they must correspond to the real **willingness** to inject the related volumes of electricity.

In particular Generating Orders express the willingness to sell a volume of electricity not higher than the one specified within the order at a unit price not lower than the one specified within the order.

Demand Orders express the willingness to purchase a volume of electricity not higher than the one specified in the order and at a unit price not higher than the one specified in the order.

The acceptance of a Generating Order involves the market participant's commitment to inject the volumes of electricity specified in the order, into the grid, in a given half-hourly period or, in case of partial acceptance of the order, the corresponding share of volume.

With the view to enhancing the operation of new entrants, the DAM in Cyprus should be capable of accommodating Simple Half-hourly Orders as well as Block Orders (at the same time). The first are the simplest form of orders, whereas the latter are a very useful tool for new generators allowing them to bid in a way that safeguards the economic operation of their units while the technical minimum constraint is met. Both types of Orders are already in use either combined or individually, in the CWE region and the Nord Pool.

Simple Hourly Orders (in Cyprus Simple half-hourly Orders are proposed) involve Demand Orders from market participants which are aggregated into a single curve referred to as aggregated "demand curve" defined for each half-hourly period of the day. Demand orders are sorted from the highest price to the lowest. Conversely, Generating Orders from market participants are aggregated into a single curve referred to as aggregated "supply curve" defined for each half-hourly period of the day. Generating orders are sorted from the lowest to the highest price.

As described in the PCR Algorithm, aggregated supply and demand curves can be of the following types:

- Linear piecewise curves (Figure 2) i.e. two consecutive points of the monotonous curve cannot have the same price, except for the first two points defined at the maximum / minimum prices of the bidding area or
- Stepwise curves (Figure 3) i.e. two consecutive points always have either the same price or the same quantity or
- Hybrid curves (composed by both linear and stepwise segments).

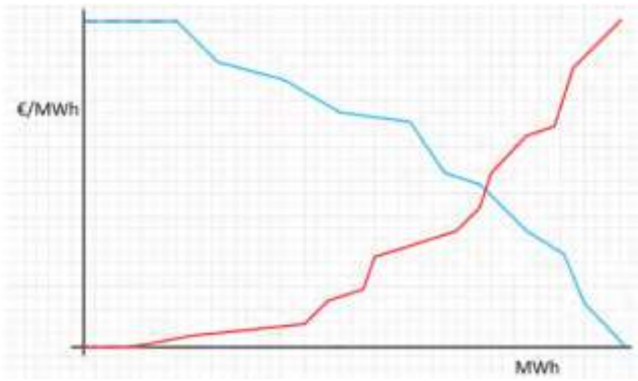

Figure 2- Linear piecewise aggregated curve

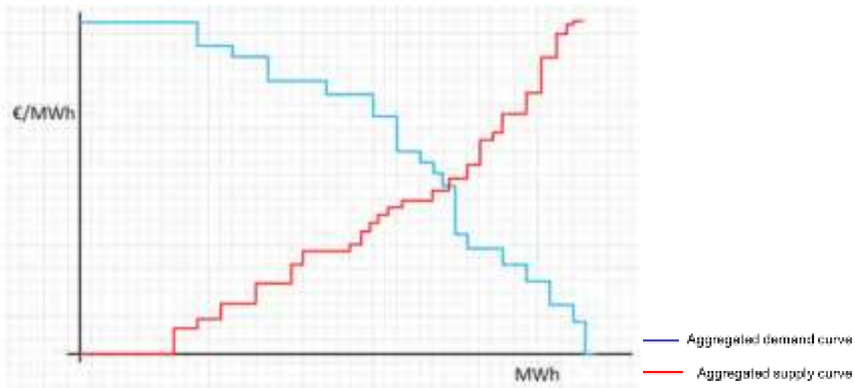

Figure 3- Stepwise aggregated curve

Demand Orders may be priced or not. A non-priced Demand Order means that the corresponding Supplier is willing to pay any price to accommodate its needs. Considering that for some years to come there will be no retail contracts with end consumers that allow flexibility for non-delivery, **it is expected that Suppliers will submit non-priced Demand Orders** (Figure 4). Nevertheless, the DAM software should be designed to allow for decreasing half-hourly load orders in the form of energy-price pairs.

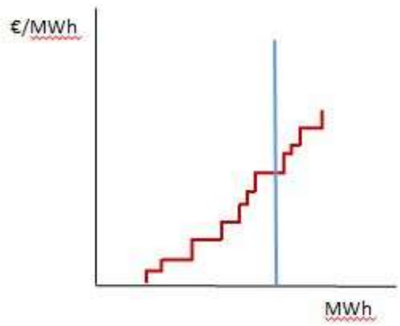

Figure 4-example of non-priced Demand Orders

Although it would be simpler for the Cyprus DAM to operate based only on Simple Half-hourly Generation Orders (as Italy does under Simple Hourly Orders) the proposal for Cyprus is to further accommodate Block Generating Orders (especially those of the Regular and Linked type) with a view to allowing generating units to appropriately self-schedule. Simple Generating Orders may have the format of increasing energy-price steps (up to 10).

A summary description of Block Generating Orders based on the corresponding description provided by Euphemia is attached in Annex B.

Linked Block Offers are accommodated in Nord Pool and are mainly utilized to schedule generating units above technical minimum under economically efficient terms.

There are also other types of Block Offers utilized in Europe's spot markets such as Profiled Block Orders, Block Orders in an Exclusive group and Flexible Hourly Orders which though are not proposed with a view to avoiding extra complexity.

It is clarified that in settlement periods for which the RES output originating from plants operating outside any NGPs is such that the DAM algorithm may either curtail some quantities or produce a non-feasible schedule for a conventional unit (e.g. under its technical minimum level) the DAM algorithm should not curtail RES quantities (provided that the corresponding offers are preferential on economic terms) but will clear a conventional unit at a non-feasible level. This issue will be handled under the ISP process run by the TSO..

5.7 Day Ahead Market Clearing Price

The DAM algorithm should match energy demand and supply for all the half-hourly periods of a single day at once.

The algorithm should return a unique market clearing price (at the point where the supply curve crosses the demand curve) per half-period, the matched volumes and the selection of block and simple orders that will be executed.

By ignoring the particular requirements of the block orders, the market problem resolves into a much simpler problem, solved using commercial off-the-shelf solvers. However, the presence of block orders makes the problem more complex. The "kill-or-fill" parameter of block orders requires the introduction of binary variables which lead to a more complicated total process. However, commercial solvers accommodating binary variables are available and therefore this should not be deemed as an obstacle.

All accepted Generating Orders are paid and all accepted Demand Orders are paying the Day Ahead Market Clearing Price as this is calculated for each half-hour period of Day D.

It is clarified that the DAM algorithm uses the load forecasts of retail suppliers as these are submitted within their offers[17].

5.8 Enforcement of liquidity within the Day Ahead market

With a view to fostering liquidity at the DAM, especially with regard to RES absorption, CERA should require at least [X] percentage of the country's consumption needs to be covered through the DAM per each half-hourly period.

In this respect, and with a view to avoiding placing barriers to the entry of new Suppliers, the above obligation will be initially placed only to the Dominant Participant's supply volumes. As competition emerges, CERA will examine the possibility for introducing relevant obligations to the supply volumes of those independent suppliers who have gained a considerable market share.

CERA in regulating the portion of the country's demand that should be traded mandatorily through the DAM should take into consideration the extent to which the Cyprus system should facilitate the entry of commercial RES penetration. CERA should seek to determine an equilibrium of the volumes to be traded within the DAM which will enable some third generators either RES or conventional to enter the market provided that their costs are competitive to the existing system LRMC.

CERA should remove barriers to entry for new comers however at a later stage and progressively, CERA should seek to provide for adequate incentives for independent generators to become competitive in attracting demand (i.e. suppliers) and therefore be less dependent on the volumes CERA will regulate in the DAM.

It is clarified that RES operating under NGPs will not be participating in the DAM but instead will be handled by EAC under bilateral contracts regime.

Considering that the Dominant Participant/s will be also trading volumes at the Forward market, the MO should every day check whether the DAM participation requirement is met.

Specifically, the MO following the DAM closure should check on a half-hourly basis, whether the Demand Order of each Supplier carrying corresponding obligation represents at least [z][18] percent of its total Final Position for each half-hour of the next day. This check will be performed following the DAM closure and in case violation is registered severe financial penalties should apply proportionally to the quantities that fall short of the above minimum percentage.

[17] In contrast to the ISP and the real time balancing process where the TSO forecasts are used.

[18] This percentage, for each supplier with corresponding liability, is calculated based on the [X] percentage of the national consumption which CERA, under a regulatory decision, has determined that should be covered through the DAM

5.9 Upper and lower limits of Generating Orders in the DAM

Considering CERA envisages no payments for long term reserves under the present over-capacity status, neither a separate capacity market (or capacity payments) accompany the wholesale market, the imposition of a low cap to the Generating Orders placed in the DAM could led to “missing money” problems. Generating units should be allowed to place orders that also reflect part of their fixed costs and therefore the cap should be set highly enough.
In this context, CERA is proposed to set the upper limit of the offers submitted to the DAM to [AO] [19]€/MWh. This is determined on the basis of the following:

a) the level of the capital expenditure the DAM should be capable of supporting and
b) the need to avoid situations of extremely high prices, which would create liquidity problems to the market.

CERA should ex-post monitor EAC’s offers in the DAM. As soon as competition enters the market (either at the supply or the generation side) EAC might have an incentive to manipulate upwards or downwards the DAM clearing price. CERA should closely follow EAC’s behaviour and provide for appropriate disincentives towards market manipulation.

As the volumes in the DAM will be rather restricted, the fear for extreme prices is rather exaggerated. For generating units to be capable of submitting high orders, that will be accepted by the DAM algorithm, sufficient demand should be utilizing the DAM platform, the same period. Considering that EAC will cover its needs mostly through bilateral arrangements (including l CfDs which will make EAC less exposed towards the DAM price even for the quantities it mandatorily purchases through the DAM), essentially only demand volumes of independent suppliers bear the risk of being exposed to extremely high DAM clearing prices. To this end CERA is considering to regulate the prices of the forward products offered by EAC generation and therefore corresponding risk is substantially limited.

Generating Orders in the DAM should be equal or greater than zero. For the conventional units of the Dominant Participant though, the lower limit should be set to each unit’s variable cost. Such an obligation is placed to the Dominant Participant with a view to avoiding damping practices.

It is noted that beyond the limits and rules concerning order prices, the design of the DAM should provide for financial penalties in relation to systematic behaviour in the quantities declared by market participants.

Therefore, Market Rules should include relevant financial penalties calculation formulas to deter systematic under or over nomination of quantities in the DAM.

[19] The upper limit for an initial period is proposed to be set to 1000€/MWh. Modifications are possible under a Regulatory Decision.

Mandatory participation in the DAM for generating units, for the total of their capacity which is not scheduled under OTC trades and type 2 replacement reserve contracts
Suppliers participate in the DAM on a voluntary basis. For the dominant participant though [z%] of its total demand needs, per half-hour, must be traded through the DAM
Simple Half-Hourly Orders and Block Orders are proposed to facilitate generating units scheduling
Simple Half-Hourly Orders for demand
For an initial period demand orders might be non-priced
An upper limit (in €/MWh) is set for the Generating Orders of all generators participating in the DAM
The Final Position of a market participant is determined as the sum of its validated Physical Nominations and the quantities cleared under the DAM
Following the DAM closure, the final positions of participants are communicated to the TSO to take them into account for the ISP
An IDM will be created within 24 months from the day the market starts operating under the new arrangements
It is proposed that the DAM opens at 10:30 EET D-1 and closes at 13:00 EET D-1
Cross-border software and corresponding platforms development is suggested to follow at a later stage

6. Optimization of RES output

6.1 Regulatory Framework for RES output curtailments

Directive 2009/28/EC, recital 60 prescribes that *"In the event that the electricity from renewable energy sources is integrated into the spot market, guaranteed access ensures that all electricity sold and supported obtains access to the grid, allowing the use of a maximum amount of electricity from renewable energy sources from installations connected to the grid"*

Moreover, under the provisions of Article 16 of the Directive 2009/28/EC: *"Member States shall ensure that when dispatching electricity generating installations, transmission system operators shall give priority to generating installations using renewable energy sources in so far as the secure operation of the national electricity system permits and based on transparent and non-discriminatory criteria. Member States shall ensure that appropriate grid and market-related operational measures are taken in order to minimise the curtailment of electricity produced from renewable energy sources. If significant measures are taken to curtail the renewable energy sources in order to guarantee the security of the national electricity system and security of energy supply, Members States shall ensure that the responsible system operators report to the competent regulatory authority on those measures and indicate which corrective measures they intend to take in order to prevent inappropriate curtailments".*

Based on the above, RES curtailment for reasons other than for technical system security should not apply. Obligations of RES under NGPs to submit generation forecasts should apply. Therefore, the Market Rules that will be developed (and correspondingly the substantial modifications needed to the TDR) should provide for RES plants under NGPs to submit generation forecasts and determine corresponding tolerance levels and financial penalties that will be approved by CERA during the approval process of the Market Rules and the new TDR.

A lot of discussions have been held as Cyprus, due its small size and limited generation portfolio, may need **on a regular basis** to switch-off and start up conventional units on uneconomical terms with a view to accommodating all RES output. Such an uneconomical operation of the system may have serious implications to the final tariff paid by the Cypriot consumers.

It might be therefore an option that curtailments of RES output (either partial or total) do take place based on overall system cost optimization during the Integrated Scheduling Process due to the small and isolated nature of the Cyprus system.

However, initially and in order to comply with the above EU Regulation the integrated scheduling process is proposed to be applied without any RES curtailments (except for system security reasons). It is furthermore clarified that the resolution of the integrated scheduling process will use updated RES generation levels as these are forecasted by the TSO on a cumulative national basis. At a later stage, the introduction of appropriate processes within the ISP that would allow for RES curtailments on an economic basis with a view to minimising the total system costs could be studied. However, given that the curtailment of RES under NGPs involves different overall costs for consumers compared to the curtailment of RES outside NGPs, the algorithm, for reasons of equal treatment, should be resolved by addressing the two categories on the basis of common economic conditions, with a view to determining the optimum amount of RES to be curtailed. Then under a post process the TSO will order curtailments equally between the two categories.

RES output curtailed only for system security reasons (no payment is foreseen in these cases)

7. Operating Reserves Procurement and the Integrated Scheduling Process

7.1 Reserves procurement principles

Markets for reserves are (or were) in some European States "capacity and energy" markets, sometime also described as "reservation and utilisation", i.e. capacity availability and energy are remunerated separately. Under such schemes the TSO is pre-contracting and paying for the availability of reserves, while energy is remunerated upon utilization in real time.

In some European markets the procurement of reserves has been organised through markets running close to real-time either under co-optimisation (with energy) processes or through separate processes which were designed to meet the each time reserve requirements of the TSO.

Based on the principle of avoiding reserves procurement under terms that distort the market and create barriers to entry for new players, the proposal is to avoid long–term commitments for reserves procurement. This is also suggested by the ACER FG which clearly dictates that TSOs should procure as many reserves as possible in the short term and as close to real time as possible, by limiting the duration of reserve contracts so that it facilitates participation of new entrants, demand response and renewable generators as well as small generators.

Paragraph 7.4 describes the details of operating reserves procurement (excluding the procurement of type 2 replacement reserve which follows a different process) through the ISP under a co-optimisation of energy with reserves approach. It is clarified that for an initial period the operating reserves availability is offered by conventional generating units and dispatchable load.

7.2 Types of Operating Reserves

Under the Load Frequency Control and Reserves Network Code (LFCR NC) the following type of operating reserves are defined:

- Frequency Containment Reserves (FCR) means the reserve utilized by a process that aims at stabilizing the System Frequency.
- Frequency Restoration Reserves (FRR) means the Active Power Reserves activated to restore System Frequency to the Nominal Frequency and for Synchronous Area consisting of more than one LFC Area power balance to the scheduled value.
- Replacement Reserves (RR) means the reserves used to restore/support the required level of FRR to be prepared for additional system imbalances. This category includes operating reserves with activation time from Time to Restore Frequency up to hours.

The Cyprus TSO under the "Analysis of operating and long term reserves requirements and payments" of the 24th of October 2013 presented its approach and corresponding requirements for the Cypriot system.

Under the proposed Net Pool arrangements the terms FCR, FRR, RR1 and RR2 are utilized to reflect the English translation of the terms "Εφεδρεία Συγκράτησης της συχνότητας», «Εφεδρεία Αποκατάστασης της συχνότητας», «Εφεδρεία Αντικατάστασης 1» και «Εφεδρεία Αντικατάστασης 2» as these are determined under the "Analysis of operating and long term reserves requirements and payments" submitted by the TSO to CERA.

We note that the Cyprus TSO in defining above operating reserves followed the definitions provided under the Load Frequency Control and Reserves Network Code (LFCR NC) with one differentiation. Replacement Reserves have been split to two sub categories. RR2 (when offered by generating units) corresponds to spinning or non-spinning reserve which is utilized to replace the previously activated FCR and FRR as well as the interrupted during the event load whereas RR1 (when offered by generating units) corresponds only to spinning reserve to deal with RES intermittency and production forecast errors (flexibility).

7.3 Procurement of Operating Reserves

Under the EB NC, balancing Services Providers may provide the above operating reserves to the TSO under the following principles:

- The price for the activation of FCR, FRR and RR volumes should be defined for each direction
- The TSO should utilise a market based method for the procurement of at least FRR and RR reserves
- Contracts for Balancing (Reserves) Capacity should not exceed one year
- Procurement of upward and downward capacity for FRR and RR should be performed separately (they could be linked only following CERA's approval). For FCR upwards and downwards, procurement may be combined.

Based on the above, it is proposed that Frequency Containment Reserve (FCR) (upwards and downwards), Frequency Restoration Reserve (FRR) (upwards and downwards) and type 1 Replacement Reserve (RR1) (upwards and downwards) are offered through the ISP (see paragraph 7.4.)

Type 2 Replacement Reserve (RR2) (upwards and downwards) is proposed to be procured through monthly contracts which will remunerate the corresponding availability reservation per direction. The monthly period is proposed to allow new entrants more flexibility in deciding, closer to real time, whether to bid or not for corresponding services. If type 2 Replacement Reserve contracts are assigned on an annual basis it might be proved that only those holding a portfolio of units (i.e. the dominant participant) will take advantage of it.

The TSO will calculate the system requirements for these types of reserves and for the first will introduce a corresponding requirement within the ISP algorithm while for the RR 2 it will enter into corresponding contracts per direction.

Contracts for RR2 could be awarded a) through a tendering process or b) by imposing an obligation to all conventional generation plants with installed capacity >50 MW to offer corresponding type of reserve in proportion to their installed capacity in relation to the system total available capacity. For plants with installed capacity above 35 MW and below 50 MW an option will apply instead of an obligation. Under the second approach, CERA would need to determine a price (possibly on a BNE approach) to be applied to all generators offering this type of reserve per direction. As generators, under the Law amendment, are decoupled from consumption, related obligations should be made in proportion to installed capacity.

<u>The tendering option is the simplest and the more market based solution as it does not require CERA to determine any price (including any profit margin) and it is therefore the proposed one for the procurement of RR2</u>. The cheapest offers will be selected until the requirement of the TSO is met. The TSO should organise a tendering process tailored to the needs of the system. CERA should approve the tendering terms following a proposal by the TSO. It is noted that CERA (due the small and isolated nature of the electricity system in Cyprus) may impose an obligation to all conventional plants, above a threshold, to submit offers to the RR2 tendering process.

There are two options for operating reserves cost allocation: either it is passed to all suppliers proportionally to consumption (i.e. only consumers are charged with this cost) or it is levied to all BRPs proportionally to the imbalances they have registered on a half-hourly basis (in which case all system users, generators and consumers, are charged). Under the second approach the reservation cost is distributed to each half-hour of the month (through appropriate coefficients application with a view to charging more those hours during which the system is in stress) and then levied for each half hour of the month to corresponding imbalanced parties on a proportional basis[20]. The first approach is proposed to be adopted for FCR and RR2 reservation costs. The second approach is proposed to be adopted for the FRR and RR1 reservation costs as these types of reserves, within the small and isolated Cypriot System under the expected significant RES penetration increase, are considered as being required mainly to address corresponding imbalances and therefore imbalanced participants either generators or consumers should bear the cost of keeping these resources available. Under this approach both generators and retail suppliers are charged for FRR and RR1 reservation costs on the basis of their imbalances. Such an approach is in line with the principle of different generation technologies requiring different amount and type of reserves which calls for corresponding cost allocation.

The compensation for availability of FCR, FRR and RR1 is paid to corresponding providers, ex-post, on the basis of the actual available capacity. For example, in case during D-1 upwards FRR is allocated to a conventional unit for five hours of day D and finally during day D the unit (due

[20] Under the process of allocating corresponding costs, imbalance volumes should not be netted. In addition, in cases of settlement periods for which no imbalances are registered, the coefficient could be such that corresponding costs are not allocated to these periods.

to an outage) was only available for two hours then the unit will be paid its offer for upwards FRR availability only for the two hours. The TSO during the following ISP runs has to take into account the non-availability of this unit until the outage is settled.

The compensation for each reserve provider is calculated, every half hour, as the product of its offer in €/MW, for each of the six relevant products (FCR, FRR and RR1, upwards and downwards availability) and the reserve in MWs found that were actually available in real time during the corresponding half hour.

The compensation for RR2 availability is made based on the monthly tendering specification provisions which will also include penalties in case of unavailability of contracted RR2.

The reserve levels corresponding to FCR and FRR requirements as allocated to generation units following the integrated scheduling process cannot be changed later during the real time balancing. Conversely, through the balancing mechanism RR1 and RR2 can be activated.

No payments for long-term reserve are envisaged as per the "Analysis of operating and long term reserves requirements and payments" submitted by the TSO to CERA. CERA has approved this approach and therefore EAC, if it considers that it is not profitable to keep a unit in the system as it does not utilize it commercially and neither receives any payment for keeping it available, should be allowed to submit a unit withdrawal request to CERA.

CERA in cooperation with the TSO, should periodically re-consider if the remaining capacity (which necessarily participates into the ISP) is sufficient to cover corresponding operating reserve requirements. In the event that above requirements are not met, CERA should introduce capacity and reserves remuneration mechanisms which will provide adequate motivation for appropriate capacity provision.

As the power system in Cyprus is an isolated one, in the absence of any interconnections back-up, CERA may examine whether it would be reasonable to contract capacity with a view to addressing emergency events. Corresponding capacity should be reimbursed for being available though it shouldn't be allowed to participate in the ISP and real time balancing in view of avoiding distortions of the prices offered under this process. In the event of an emergency, market rules are suspended and the TSO may utilize such capacity at administratively set prices (see para 12.9). Corresponding cost should be passed at the wholesale level proportionally to all suppliers.

Demand side (dispatchable load) could also participate to operating reserves procurement, provided it holds appropriate technical capabilities to meet activation times set by the TSO under each type of procured reserve.

7.4 Integrated Scheduling Process

Following the public consultation, a central Integrated Scheduling Process (ISP) which will take place during the afternoon of D-1 is proposed:

a) for the procurement of reserves to be made on a more cost-effective basis and

b) to meet the request, suggested by all consultation participants, to allow the possibility of signing bilateral agreements and participating in the DAM with quantities which do not necessarily meet the technical minimum requirement of conventional units.

The ISP is part of the overall architecture of the market design and aims at implementing a technically and economically optimal solution for the operation and scheduling of the generation units in Cyprus, bringing the best economic result for the Cypriot consumer.

As the DAM and the forward market, under the new arrangements, can provide for a technically non-feasible program, a process which will ensure the technical feasibility of the system is introduced. Considering the energy mix and the technical parameters of the system in Cyprus, it is further proposed, through this process, the procurement of operating reserves (except RR2) to be effected so as the whole mechanism to yield the optimum financial result for the Cypriot consumer in total.

The proposed process will take place during the afternoon of D-1 in order to:

a) ensure a technically feasible solution

b) allocate operating reserves requirements on generation units (and/or dispatchable load) closer to real time (excluding RR2 which will be ex-ante contracted by the TSO under monthly tendering) and give the TSO the possibility for more flexible and tailored to the system needs procurement of operating reserves, on the basis of real system[21] needs at all times and

c) take necessary measures, through preventive upwards and/or downwards units' scheduling, with a view to addressing deviations which emerged on the D-1 afternoon.

Participation in the Integrated Scheduling Process is mandatory for all conventional units with an installed capacity of above [5] MW. The participation of dispatchable load is optional. RES plant with appropriate technical capabilities are allowed, on a voluntary basis, to submit downwards balancing energy bids to be utilized in the balancing mechanism.

Through this process, participants interested to provide availability for FCR, FRR and RR1 in the Cyprus system should participate in a daily auction for both reserve availability and upward and downward balancing energy. Daily reserve auctions, provided that transparent and non-discriminatory compensation rules are applied, have been proven to be the most appropriate procurement procedure that also enhances the operation of newcomers in generation.

[21] It is clarified that the TSO should publish, at the latest by hour 9:00 of D-1, its requirements for operating reserves for each half-hour.

Generators should submit their bids and offers for balancing energy and for maintaining reserves availability (for each of their generation units) in the afternoon of D-1 (e.g. at 16:00) and the indicative program will be made publicly available [x] hours later. The proposed process in order to produce the indicative programme co-optimizes the balancing energy with the reserves by solving a Mixed Integer Linear Programming model (MILP) for unit commitment using both binary and continuous variables. The binary variables are introduced to take account of the startup and shutdown of each unit (and the associated costs) since the process can start or shut down a unit, if needed.

It should be noted that the proposed process should commence taking into consideration the commercial programs of the units as they are declared following the DAM closure[22] and should include transparent and non-discriminatory rules to ensure that:

a) the programme of the units stemming from the forward market and the DAM would be amended only:

i) to cover specific and justified technical constraints (an exhaustive rather than an indicative list should be formed by the TSO during the process of Market Rules development) and

ii) to implement the procurement of reserves (FCR, FRR and RR1 upwards and downwards)[23] based on the economics of the offers in both energy and reserve availability (co-optimization) and

b) the financial result for the market participants will not be modified for the worse in relation to the economic status these participants have registered following the forward market and the DAM.

During the ISP, the TSO will use its own forecast for both the overall system load and the national RES output.

Any modification of the parameters entering the ISP should be recorded and justified by the TSO.

In the morning of day D, the ISP is proposed to be repeated once again for the second half of day D as it is expected that the TSO will become aware of updated data on system demand as well as aggregated RES generation. For the second ISP run the same offers submitted during the afternoon of D-1 will be used. There will be no re-submission possibility for the bids and offers for both availability of reserves and balancing energy.

However, in case of an extraordinary event that takes place during the day D, or even in the afternoon of D-1, which greatly affects the scheduling of the units and the allocation of reserves (e.g. a unit outage or a major unexpected increase in system load) the TSO should be allowed to run again the ISP by introducing in the algorithm the significantly updated data.

[22] When an IDM will be operational the subsequent ISP should take into account the final positions that will be formed after the IDM

[23] Given the isolated nature of the Cypriot System, the ISP algorithm could include locational and dispersion requirements for operating reserves procurement on the basis of the TSO requirements for a secure system operation

The real time balancing mechanism (for which the balancing energy offers submitted in the afternoon of D-1, without re-submission option, will be taken into account) will respect and keep intact the levels of FCR and FRR as these have been allocated by the ISP. RR1 reserve that has been allocated in the afternoon of D-1 as well as RR2 reserve allocated through an ex-ante tendering procedure can be activated by acceptance of the relevant balancing energy bids and offers. I.e. the balancing mechanism can activate RR1 and RR2 in real time. Exclusion of these reserves from participating in the balancing mechanism would lead to unnecessary increase of the balancing cost. Thus the real time balancing mechanism uses as an input parameter the levels of FCR and FRR reserves (as allocated under the ISP), maintains them to the corresponding units and only runs to allocate upward and downward balancing energy on the remaining units or other participants who hold relevant technical capabilities.

In summary, we could say that in the afternoon of D-1, an auction will take place for the following products:

1. Six (6), distinct, half-hour reserve availability products in €/MW:
    a) FCR (upwards and downwards)
    b) FRR (upwards and downwards)
    c) RR1 (upwards and downwards)[24]

2. Two (2), distinct, half-hour balancing energy products (upwards and downwards) in €/MWh.

The half-hourly bids that will be accepted for availability reserves (in €/MW) for the six distinct products, in case they are accepted, will be paid their bid (pay as bid).

Bids and Offers accepted for balancing energy will be paid the corresponding marginal price defined by the balancing mechanism optimization process (on a half-hourly basis two marginal prices[25], in €/MWh, will be calculated: one for upwards energy and one for downwards energy).

Generation units should submit bids and offers for balancing energy (downwards and upwards) corresponding to all possible capabilities they hold for upward and/or downward energy provision, independently of their Final Position as this is determined following the closure of the DAM (i.e. generation units will carry an obligation to offer their entire capacity including volumes committed under the forward market or/and the DAM).

Participants' positions as instructed by the TSO following the ISP (except in the case referred to in paragraph 8.9.) do not involve any economic settlement. They are indicative. During balancing in real time, the TSO's final dispatch orders will be formulated which will produce economic result for participants.

[24] The non-spinning RR2 reserve could be procured by the TSO on an ex-ante basis- [x] months in advance
[25] It is clarified that each balancing energy bid or offer may include more than one pairs of quantity-price

The results of the ISP which the Regulator could be in position to monitor at any time, include the following data on a half hourly basis:

1. An indicative generation units' dispatch programme which will be finalized under TSO's dispatch orders in real time, adjusted to take into account the actual conditions of the system (actual demand and actual RES output)

2. Allocation of reserves (FCR, FRR RR1) per conventional unit or per dispatchable load with corresponding technical capabilities.

This procedure, as described above, comprises a version of the so called "Integrated Scheduling Process" determined by ENTSO-E Network Code on Electricity Balancing (NC- EB).

During the development of the ISP software, CERA will monitor and approve all details and assumptions introduced for the ISP solution. As under the Law, CERA is responsible for market monitoring, when the market starts operating under the new design with the application of an ISP by the TSO, CERA should, on a daily basis, receive from the Market Operator and the TSO a set of information allowing it to detect any distortion and/or strategic behaviour that could potentially distort the market outcome. For this purpose, during the software development an automated process should be foreseen for data transferring to CERA in a form that the Authority can process it. Upon completion of the Market Rules, CERA shall issue a Decision which sets out precisely the information to be sent by the TSO and the Market Operator.

7.5 Other Ancillary Services

Other Ancillary Services, apart from Operating Reserves, which the TSO should procure from market participants to safely operate the system, such as black start and reactive power control should not be part of the ISP and real time BM arrangements but procured separately and charged to the total of the system customers (as per the corresponding new tariffs methodology to be issued by CERA).

An ISP process is introduced which is mandatory for all generating units with installed capacity over [5] MW
FCR, FRR and RR1 procurement is made through the ISP
Monthly contracts for RR2 reservation
Demand side could participate in reserves and balancing energy provision provided it holds appropriate technical capabilities

The real time balancing mechanism respects the FCR and FRR levels allocated by the ISP
Utilization of RR1 and RR2 reserves is possible through the BM
FCR and RR2 reservation costs are charged to suppliers on a proportional basis
FRR and RR1 reservation costs are charged to all imbalanced participants
Black start and reactive power control procurement is made outside the ISP and the real time BM

8. Real Time Balancing

8.1 The real time Balancing Process

As earlier described, the Final Positions of generating units are determined through their validated Physical Delivery Nomination and the DAM scheduled volumes.

The TSO following the ISP under which FCR, FRR and RR1 reserves are allocated, runs a process of matching in real time system load with available generation resources, known as system balancing. In doing so the TSO should develop a Balancing Mechanism (BM). As earlier described, the participation to the ISP, during which the submission of bids and offers for balancing energy is also taking place, is mandatory for generation units above [5] MW. Dispatchable load and RES plants may (on an optional basis) submit bids and offers for balancing energy.

Under the ACER FG EB “The Network Code on Electricity Balancing shall allow BSPs to place and or update their bids as close to real time as possible and at least up to one hour before real time”. However,, such an approach (i.e. submission of updated balancing energy bids and offers) when an ISP is applied, which co-optimises energy with reserves, could possibly lead to abusive behaviour from participants who know with certainty, already by the afternoon of D-1, that the ISP has dispatched them for providing reserves and therefore they have an incentive to resubmit higher balancing energy offers. Therefore, it is proposed that balancing energy bids and offers are submitted once without resubmission, closer to real time, possibility[26].

The proposal is for Bids and Offers in the Balancing Mechanism (BM) to be placed by Balancing Service Providers and RES plants holding corresponding capabilities[27], per unit in case of generators, until 16:00 EET on D-1 without resubmission possibility. From that point onwards and up to 30’ prior to real time the TSO should appropriately instruct increments and decrements to match generation with demand, based on the D-1 submitted bids and offers. It is clarified that for the real time balancing process, the TSO addresses RES plants submitting bids for balancing energy as dispatchable generation units and is therefore, not taking into account corresponding RES output within the national RES generation forecast.

Submission of bids and offers for balancing energy is mandatory for all conventional generating units above [5] MW for all their available capacity. Offers for availability of FCR, FRR and RR1 are submitted during the afternoon of D-1 along with the bids and offers for balancing energy.

The Balancing Mechanism shall run and produce dispatching instructions for every 30 min of day D (i.e. the BM program time unit equals the Imbalance Settlement period[28]).

[26] At a later stage of the market operation, CERA could investigate the possibility for allowing balancing energy bids and offers resubmission closer to real time provided that the updated offers will be more economic for the TSO compared to the first

[27] RES plants can only place bids for balancing energy

[28] According to ACER FG on EB, the balancing programme time unit should be consistent with the imbalances settlement period. Our proposal is to set both equal to 30’. The proposal is based on the assumption that metering capabilities are

The BM should run an optimization function to activate balancing energy based on submitted costs through a non-discriminatory, fair, objective and transparent mechanism which minimizes the costs of balancing, whilst takes into account technical (e.g. synchronization, minimum up, minimum, down ramp up and ramp down times etc) constraints and respects the levels of FCR and FRR allocated under the ISP. Balancing energy can be provided by any generation unit (or RES plant or dispatchable load) regardless of whether this unit has been committed to offer reserves or not.

Ranking of offers is made from the lowest priced to the highest priced whilst ranking of bids is made from the highest (in absolute terms) to the lowest priced.

As per the draft EB NC of ENTSO-E, in case the activation of balancing energy for balancing purposes deviates from the merit order then the TSO should report the incident.

It is clarified that Bids and Offers in the Balancing Mechanism are submitted to the MO along with the offers for FCR, FRR and RR1 availability and then directly notified to the software run by the TSO.

8.2 Balancing Energy and Reserves Capacity

Balancing Energy consists of both energy activated in real time by RR1 and RR2 providers and energy provided under the Balancing Mechanism by all other available resources.

"Balancing energy" is distinguished from "reserves capacity" based on the following principles:

- Ahead of real time (i.e. before the gate closure time of the last market in which participants can trade energy), the TSOs secure access to power generation capacity for control purposes. In its position paper on cross border balancing[29] ENTSO- E refers to this power generation capacity (in MW) as "reserves". In the past the most common means of securing access to these reserves were ex-ante contracts for Reserves[30].
- Close to and in real time, energy is activated either from pre-contracted reserves or other available resources in order to maintain the balance between demand and supply. This delivered energy (in MWh) is referred to as "Balancing Energy".

designed to meet the 30' requirement. In case metering requirements could also accommodate the 15' horizon then the balancing time unit could be set to 15' as it is deemed as more efficient. In that case the imbalance settlement period could also be set to 15'. Participants positions at the DAM'which is a 30' market in such a case could be split in two identical 15' positions for settlement purposes. Moreover, for co-optimization purposes balancing energy bids and offers will be submitted to the ISP on 30' basis and then will be split to two 15' offers so as to be utilized in the balancing mechanism.

[29] *Position Paper on Cross-Border Balancing*, ENTSO-E, July 2011.

[30] We note however, that market based mechanisms closer to or in to real time have meantime been developed in other jurisdictions (e.g. UK, Italy, and elsewhere) as a means of accessing reserves without creating market distortions.

8.3 Balancing Service Providers

During the first phase of the market operation, conventional generating units and dispatchable load can provide balancing services, referring both to availability of operating reserves and balancing energy.

RES operators holding appropriate technical capabilities should be allowed to provide downwards balancing energy in view of adapting to ACER's FG which require generation units from renewable and intermittent energy sources to become BSPs. However, it is clarified that during a first phase RES plants do not participate to operating reserves provision due to their intermittent nature.

It is further clarified that RES plant participation to the BM through bids for downwards balancing energy applies only to RES plants outside any NGPs. RES aggregators, provided that they hold adequate technical capability, may also participate to the BM in which case the total of the RES plants they represent is addressed as one "virtual" plant with specific energy absorption capabilities.

Balancing is offered by Balancing Services Providers (BSPs) in the form of Bids for energy absorption from the system or Offers for energy injection into the system[31].

The BM process will produce bids and offers acceptance which will be transposed to Dispatch Orders issued by the TSO. Such Dispatch Orders entail obligations for the generators and the dispatch able load participating in the ISP and real time balancing process .

8.4 Bids and Offers placed by generating units to increase or decrease generation

The format of the Offers submitted to the balancing mechanism should **at least** foresee for differentiated prices between the following two cases:

a) generation increase from zero production level up to the technical minimum of a conventional unit

b) generation increase from the technical minimum up to the maximum seasonal generation level of a conventional unit.

The format of the Bids submitted to the balancing mechanism should **at least** foresee for differentiated prices between the following two cases:

[31] In market environments, bid prices are usually close to corresponding variable costs of the parties providing the services, since such units are already scheduled at the contracted level and thus fixed costs are already covered. Therefore, such units are willing to pay any price below their variable cost to reduce generation, a practice which creates extra profit for them. On the other hand, offer prices are usually based on the spot market price plus a premium reflecting missed revenues by not selling in the spot market.

a) generation decrease from the maximum generation level down to the technical minimum of a conventional unit

b) generation decrease from technical minimum to zero (shutting down).

The maximum number of quantity-price pairs is set to ten. Especially with regard to RES plant participating in the balancing process, the design should allow negative priced bids for downwards balancing energy (RES outside NGPs under bilateral contracts who are paid on the basis of the metered quantities should be allowed to place negative bids in exchange of their lost income).

Offers shall be ranked in non-decreasing price order from the lowest-priced offers to the highest-priced ones. Bids shall be ranked in non-increasing price order from the higher to the lowest-priced ones.

8.5 Bids and Offers placed by dispatchable load to increase or decrease demand

Dispatchable load may place offers to decrease consumption i.e. to sell energy to the system. Corresponding offers will be taken into account in determining the upwards balancing energy marginal price. Accepted offers for demand decrease are paid to the supplier, representing the corresponding dispatchable load, by the MO at the corresponding marginal price. Similarly, dispatchable load may place bids to increase consumption i.e. to purchase energy from the system. Corresponding bids will be taken into account in determining the downwards balancing energy marginal price. Accepted bids for demand increase are paid to the MO by the supplier representing the corresponding dispatchable load, at the corresponding marginal price. For simplification purposes during the first phase of the market operation single price-quantity pairs for each half-hourly period are suggested to be placed for demand increases/decreases.

This arrangement will be initially feasible for large consumers with appropriate technical characteristics which could provide balancing energy either by also acquiring the status of retail supplier themselves or through their retail supplier. However, as described under Section 13 Demand Response activated through Demand Response Agents should also <u>be possible in the future</u>, through offers for demand curtailments.

8.6 Payments for balancing energy provision

Theoretically, if participants in the balancing mechanism had an accurate view of how demand and supply would evolve every half-hour of the next day, the results between the two alternatives (pay as bid or pay as cleared) would be equivalent. If, under the pay as bid approach, generators could accurately predict the each time marginal unit, they would submit offers priced at the cost of the marginal with a view to maximizing their revenues i.e., the expense for the system would be the same in both cases. However, because there can be no forecasting accuracy, under the pay as bid approach inefficiencies in the way offers are priced are created, leading to inefficiencies in the way offers are selected.

Marginal payment is considered to lead to fewer distortions, as it motivates generators to offer very close to their marginal costs knowing that if another more expensive offer is accepted they will be paid the expensive price. Therefore, offers under a pay as cleared approach are based on actual costs rather on participants' estimates of how balancing will evolve and which units will be used. Moreover, when marginal pricing is applied, participation in the balancing mechanism becomes simpler for participants; especially for new entrants who have gained no market experience that would allow them to maximize their revenues through appropriately priced offers' submission, as the case is in "pay as bid" markets. **For these reasons, compensation of those providing balancing energy is proposed to be made at the marginal price of the balancing energy, per direction.**

The marginal price for the balancing energy is determined per direction under the optimisation problem of the balancing mechanism within which the bids and offers for balancing energy submitted in the afternoon of D-1 are taken into account.

Specifically, when the system is in deficit (short) the TSO is expected to accept offers for generation increase or for demand decrease. Offers accepted under the balancing mechanism are paid the marginal price of the upwards balancing energy of the corresponding settlement period. This price comprises also the imbalance price to be applied to those parties found out of balance.

When the system is in excess (long) the TSO is expected to accept bids for generation decrease or demand increase. Bids accepted under the balancing mechanism are paying the marginal price of the downwards balancing energy of the corresponding settlement period. This price comprises also the imbalance price to be applied to those parties found out of balance.

For those cases when the system is short but the TSO must enable generation decrease or demand increase, providers are paying the marginal price of the downwards balancing energy. Respectively, when the system is long and the TSO must accept offers for production increase or demand decrease providers will be paid the marginal price of the upwards balancing energy.

8.7 The Dominant Participant's bids and offers in the Balancing Mechanism

Balancing Mechanism products can be priced either only reflecting variable costs or reflecting both variable and fixed costs.

Mandatory bidding is not the same thing as regulated pricing. The European model is clearly trying to move the market to one where market participants manage their own commercial behaviour and the NRAs only intervene where a participant's behaviour harms customers or other market participants.

However, one area that NRAs need to be mindful of is the bidding behaviour of participants with a controlling interest in the market or sections of the market. In these parts of the market it is possible for a participant to bid prices that cannot be undercut by a competitor or withhold critical volumes and force the TSO to accept offers by less economically efficient units.

This is where monitoring by NRAs plays a key role. Ex-post monitoring and imposition of penalties should be enough to protect the market from the above mentioned practises, which requires adequate capacity to be placed with the regulator with a view to allowing it to efficiently prevent market abuse.

In this context, and with a view to avoiding strategic behaviour, it is required that the dominant participant's bids for downwards balancing energy reflect at least the minimum variable cost, on a per unit basis. The offers of the dominant, for upwards balancing energy, should be within a regulated range between the minimum variable cost of each unit and a common upper limit determined by CERA to [AO][32] in €/MWh.

In case of Cyprus, the current 100% dominancy of EAC in balancing services provision has been extensively discussed as a potential source of abusive behaviour resulting to increased tariffs for market participants (due to increased imbalance and system costs).

There are two alternatives this issue could be addressed: a) through ex-ante regulation of EAC's offers on a per unit basis, based on corresponding marginal costs or b) through ex-post control of the company's offers. After examination of both alternatives the preferred approach, taking into account the structure of the electricity sector in Cyprus, is the second. The first approach requires accurate, fair and in advance calculation (on the basis of a market simulation) which however, is difficult to achieve and in any case could lead to market distortions. Given that the range of offers for each unit will be pre-approved EAC is expected, in most cases, to exhaust the allowed range as it will face no ex post consequences. This is a practice that may unnecessarily increase the overall cost of balancing. Conversely, ex-post regulation seems to provide better incentives for more economic offers by the dominant participant as it will face severe fines for over-recovery.

Specifically, CERA is proposed to perform monthly checks, **on a per unit basis**, with regard to the company's offers and income through reserves and balancing energy procurement. Those amounts will be compared with the values approved by CERA in in the process of dominant's retail prices regulation. Moreover, the company's offers for reserve availability will be monitored each month (on an ex-post basis) to ensure that the corresponding costs borne by the TSO are reasonable (cost data on the basis of the BNE approach or real reservation costs by each unit could be used for respective periods and capacity ranges). The details of this ex-post monitoring process will be determined by CERA at a later stage.

It is clarified that the tenders for operating reserves availability will be checked in conjunction with the offers for balancing energy in order to determine whether the dominant participant is over -recovering its costs through combined use of the ISP and the real time BM. In case

[32] Equal to the corresponding upper limit applied to the Generating Orders submitted to the DAM

submission of offers leading to over-recovery a fine[33] will be imposed for abusing its dominant position.

The software to be developed by the MO and the TSO should be able to send CERA data of the offers placed by all participants, in an automated manner, and in a format that CERA can process it. This way CERA will be able to detect and promptly treat any strategic behaviour related to the dominant participant's offers for balancing energy and operating reserves.

8.8 Upper limit of the offers submitted by conventional IPPs to the balancing mechanism

Given that independent power generators will be competing EAC offers, which will be determined within the above discussed framework, EAC's offers will signal, most of the time, the upper limit IPPs could compete with. Only during those hours for which the independent generator knows with certainty its offer will be accepted (due to capacity scarcity) it may submit excessively priced offers for upwards balancing energy. Offers should therefore not exceed the upper limit set to [AO] €/MWh.

To avoid speculative behaviour through exploitation of the price difference between the DAM clearing price and the downwards balancing energy clearing price, bids for downwards balancing energy of all conventional generating units (including the units of the dominant participant) should reflect at least the minimum variable cost of each unit.

The alternative approach under which bids for downwards energy should be set at least equal to the corresponding offers made by each unit to the DAM has been rejected. The participation in the ISP is mandatory and therefore the acceptance of a balancing energy bid at a price at least equal to the corresponding offer made to the DAM would deprive market participants from any profit (above their variable costs) they have managed to achieve through the DAM. It is noted that the DAM has been designed to allow participants to recover part of their capital costs as there is no capacity market or other type of capacity remuneration mechanism provided. It is therefore considered as more appropriate to oblige generators to pay back the variable cost they have not finally faced independently of the height of their DAM offer or DAM clearing price. Furthermore, for that part of the generation output which is contracted under the forward market (for which there is no centrally calculated price) the above approach linking the downwards balancing energy bids with the DAM offers or DAM clearing price has no relevance.

[33] The fine is imposed with a view to preventing the abusive behaviour which affects the activities by alternative suppliers. It is noted that such a behaviour is not expected to pose extra costs to the final consumers as CERA through retail tariffs regulation has the ability to prevent cost over-recovery passing to retail tariffs. However, this issue deserves careful treatment by CERA as otherwise it could distort fair competition conditions. The fine imposed in such cases is forwarded to those, at the wholesale level, who have been harmed by the abusive behavior in accordance with the provisions of paragraph 12.12.

8.9 Special Arrangements

To ensure that the ISP will lead to an ultimate financial outcome which is not resulting in a worse situation for market participants in relation to the financial outcome these participants have registered following the forward market and the DAM, the adoption of an additional mechanism is proposed. Under this mechanism participants to the balancing mechanism will be compensated up to their offer in case the clearing price for the balancing energy falls bellow these specific offers (bid recovery)[34].

It is also clarified that generation units with Final Positions not meeting their technical minimum, **will be allowed, under the ISP, to bid for downwards balancing energy (generation reduction)** from the theoretical (although technically not feasible) level of their Final Positions down to zero generation output. In case these units are not finally scheduled under the ISP and the subsequent real-time balancing mechanism then it is considered as if the TSO has accepted their bids for downwards balancing energy from their Final Position level to zero and these units should pay the TSO the marginal price of the downwards balancing energy. In such cases the TSO instructions under the ISP process result in a financial settlement for corresponding participants.

Obviously, in these cases the offers (for downwards balancing energy) will be also required to reflect at least the minimum variable cost of the units, the accuracy of which is controlled by CERA.

The alternative approach under which no such possibility is allowed for generation units was also considered. If the above theoretical bid approach is not allowed, when the technical minimum is not met and the ISP is not dispatching a unit, this unit will then appear to be out of balance for the total of its commercial program and should therefore take the corresponding risk towards the imbalance price that will emerge for the corresponding periods. Although such an approach in mature markets would be considered as legitimate in order to prevent the risk of speculative behaviour on the part of the producers, in case of Cyprus, the presence of the dominant participant and its de facto ability to determine the imbalance price, is considered as possibly distorting the smooth operation of the market. Such a distortion would deter new entrants in generation and therefore this approach is rejected.

Bids and Offers for balancing energy absorption or injection to the BM are submitted once, at the day-ahead time frame by 16:00 EET and are also taken into account for co-optimisation purposes under the ISP
Bids and Offers for balancing energy are submitted to the MO and directly transferred to

[34] The optimization process run during the real time balancing is possible in some cases to calculate marginal prices for upwards balancing energy which fall under the “highest” accepted offer due to the fact that some generation units have been committed under a co-optimization process

the software platform which runs the ISP and the real time balancing
Balancing energy is remunerated at the marginal price corresponding to the upwards or downwards direction
The marginal price of the balancing energy at the direction of the system imbalance sets the imbalance price
Mandatory participation for thermal generating units above [5] MW to the real time balancing mechanism for the total of their capacity
Dispatchable load may participate in the BM
RES plants outside NGPs may participate in the BM for downwards balancing energy provided that they hold appropriate technical capabilities
Negative bids, placed by RES plants, are allowed
Bids and offers by the dominant participant are ex-post regulated. Over recovery as well as wrong declarations regarding the availability of units lead to penalties which are allocated to those being affected by the abusive behaviour
The following rules apply to all balancing energy providers: a) upper limit set to [AO] €/MWh for the upwards balancing energy offers b) downwards balancing energy bids to reflect at least the minimum variable cost of each unit
Furthermore, for the dominant participant a lower limit for its upwards balancing energy offers is set equal to each unit's minimum variable cost

9. Participants' Settlements

9.1 Imbalance Volume Exposure

Imbalances are charged to market participants with regard to whether they have fulfilled their commitments towards the market and towards the TSO (dispatch orders) or had to buy (or sell) additional quantities.

The metered quantities of market participants are checked towards their Final Position. The difference is deemed to be purchased or sold from/ to the system and is therefore charged or credited accordingly, at the imbalance price. Quantities corresponding to Dispatch Orders by the TSO[35] are considered as contractual obligations and therefore are not counted as imbalances.

For each conventional generating unit, each RES plant operating outside NGPs > 1 MW and each RES aggregator and for each half-hour, the difference between the measured quantities (per unit or per plant[36]) is compared with the corresponding Final Position, as this has been determined and notified to the TSO right after the DAM closure. The TSO taking also into account any dispatch orders (which are not counted as imbalance volumes) calculates the difference which comprises the imbalance volume of the half -hour.

For RES plants outside National Grant Plans[37] which participate in the market and for which there is an imbalance risk due to the inability for accurate generation output forecast, and until an Intra-day market is organised, a tolerance margin is introduced to protect them from excessive imbalance charges (on both directions). This margin should be determined in the Market Rules and approved by CERA and should be linked to the size and relevant RES technology.

As already mentioned, the TDR should be amended in conjunction with the market Rules and should impose fines in cases of erroneous forecasts by RES plants owners operating under NGPs. It is considered as appropriate that corresponding margins, in both procedures, are harmonized.

For each retail supplier and for each half-hour, the difference between the measured quantities (as measured for all interval meters represented by the supplier and as profiled for all non-interval meters) is compared with the Final Position of the supplier, as this has been determined and notified to the TSO right after the DAM closure. The TSO taking also into account any dispatch orders to dispatchable load (which are not counted as imbalance volumes) calculates the difference which comprises the imbalance volume of the half -hour. For suppliers serving

[35] These orders, to the segment they differ to participants' final positions, ultimately correspond to accepted bids and offers under the real time balancing

[36] for aggregators the actually per plant metered quantities will be summed up and compared with the cumulative Physical Position of the aggregator

[37] It is clarified that the margin does not apply to the imbalances registered for the RES plants under NGPs which are represented by EAC. If such a tolerance margin were applied the excluded imbalanced quantities would either cause damage for EAC (in case EAC was due to receive money for corresponding quantities) or would cause unfair profits (in case EAC was due to pay money for corresponding quantities)

limited volumes (i.e. suppliers with limited capabilities to aggregate imbalances) CERA should provide for a tolerance margin of the order of 15% prior of applying any imbalance charges.

9.2 Imbalance Price

Imbalance prices will be calculated depending on whether the system is short or long.

When the system is in deficit (short), the imbalance price of the corresponding half-hour is determined by the upwards balancing energy marginal price, as this is calculated under the real time balancing optimisation process.

When the system is in excess (long), the imbalance price of the corresponding half-hour hour is determined by the downwards balancing energy marginal price, as this is calculated under the real time balancing optimisation process.

9.3 Imbalance Charges

Imbalance charges are calculated based on the single pricing settlements. Meaning each market participant which registers imbalance volumes pays when is short (independently of the system direction) or is paid when is spilling (independently of the system direction).

Alternative options to the above proposed single pricing approach have been examined:

Under the dual pricing approach two imbalance prices (the marginal of offers and the marginal of bids) are calculated when the system is short and similarly two prices are calculated when the system is long. The marginal of offers is paid by those market participants being short (both when the system is long or short) while the marginal of bids is received from those spilling (both when the system is long or short). Such an approach is particularly penalising in cases of short positions independently of the overall system direction while it provides for lower compensation in cases of long positions (again independently of the overall system direction) and it is therefore not proposed for an immature market like the Cyprus one .

The approach of imbalance parties not being penalised in case they contribute to balance the system (i.e. their status is opposite to the system one) requires that all market participants have the same possibility of projecting the system status (or even influencing it by withholding capacity) which definitely is not the case for the immature Cyprus market.

The hybrid, two-prices, settlement has been also examined. This is similar to the dual pricing however, the one of the two prices applied is the DAM clearing price. This option has been rejected for reasons similar to those under the dual pricing.

An additive component to the imbalance price applied when generating units (including RES plants) are spilling, has been considered with a view to avoiding such behaviour. An additive component means that in case of spilling the corresponding market participants would receive a price lower than the imbalance price of the half-hourly period. The application of such a component is considered with a view to preventing[38] systematic spilling (both by RES plants and conventional units) as corresponding generators will tend to exploit the expected higher imbalance prices (compared to the DAM clearing prices). Such a component will result to a surplus gathered at the MOs' account which would be addressed as per the proposals under para 9.5. However, as this measure could potentially excessively penalise newcomers in generation (especially RES operators) which do not hold experience in market operations, CERA is proposed to monitor the evolution of prices both in the DAM and for imbalance settlement and in case systematic spilling behaviour is detected the measure should apply.

Under the existing rules in Cyprus, an adjustment is applied towards non-delivery of accepted bids and offers (non-delivery rule) for balancing units. The settlement is carried at a price equal to the difference between the imbalance price and the price paid to the successful bidder[39]. The aim is to create a disincentive for generators to offer high prices to increase generation and eventually generate less than the accepted offer, knowing that they will be paid the high accepted offer price and pay back only the imbalance price which is an average price. Such a non-delivery rule is no longer required once the approach of marginal pricing is adopted.

9.4 Balance Responsible Parties

Balance Responsible Parties (BRPs) could be formulated under the proposed design (apart from RES aggregators which by default undertake the role of BRP) to undertake the financial responsibility towards the MO for the imbalances of the market participants they represent.

There are two options for the arrangements applied for BRPs: either the volumes are netted or the cash flows are netted. Since a single imbalance price is proposed the above two options provide for an equivalent result.

In case though different imbalance prices apply (e.g. in case CERA opts to apply an additive component for spilling) then netting of imbalance volumes instead of cash flows returns different economic results which could be considered as favouring those managing large portfolios i.e. only the Dominant, during an initial period. However as the market matures and other portfolios are also created, BRPs should be capable of undertaking responsibility over the netted volumes of their group (sum of all physical positions towards the sum of all metered quantities) and therefore the software to be implemented should allow for such a possibility that may be activated in the future.

Therefore, the design in the beginning is proposed to count separately the imbalance volumes per conventional generating unit, per RES plant operating outside NGPs, per RES aggregator and

[38] It is noted that the design already provides for an incentive for participating generators to declare as "accurately" as possible their generation levels and avoid corresponding imbalances as they will be called to pay FRR and RR1 reservation costs in proportion to the imablances they register (without netting)

[39] Within the existing rules accepted bids and offers are paid as bid

per retail supplier and then assign corresponding cash flows based on the each time imbalance price applied.

To avoid though unnecessary money transfer, a BRP may be formulated to serve a diversified portfolio of market participants (i.e. both generating units and suppliers). In that case corresponding cash flows, per invoicing cycle, from and to the MO could be netted. Obviously the BRP will have to economically settle with its members but this will be done outside the market.

It is clarified that the BRPs only undertake imbalance settlements. Participation in the DAM, bids and offers to the ISP and the real time balancing as well as dispatch orders are separately handled for each market participant.

9.5 Management of Settlements

The real time BM platform operated by the TSO notifies the results of each half-hourly period to the MO with regard to the final dispatch orders issued by the TSO and the each time imbalance price. Three working days following the end of each month the TSO and DSO forward the MO the certified metering data including representation percentages for those suppliers serving customers with non-interval meters with respect to the half-hourly periods of the previous month.

The MO, taking into account the OTC registered quantities, the DAM scheduled quantities, the dispatch orders, the BM data and the metering data performs the cash flows calculation and invoicing as per para 12.8

Although the single pricing for imbalances settlement is proposed, this does not lead to the MO being 100% financially neutral towards market participants. This is a situation occurring because the balancing services activated in the opposite direction (than the system's one) are paid (or paying) the marginal price of their direction whereas the rest of the market pays (or is paid) the marginal of the main direction. The introduction of a bid recovery mechanism will also tend to increase this outcome. Therefore, surpluses or deficits at the MO account are created for each settlement period which has been set to 30'. The application of an additive component to address spilling, if applied, will increase this tendency.

The proposal is that the surplus or the deficit of each half-hour are gathered and netted at the end of each month and proportionally returned or charged (depending on whether surplus or deficit) to all suppliers on a proportional basis (uplift).

The above mechanism bears the disadvantage of not providing for the appropriate signals to those creating the most imbalance however it is the most transparent and simple one.

Sophisticated formulas that spot the "right" and "wrong" behaviour of market participants and reward or penalize them accordingly are not deemed as adequate at least during the first years of market operation.

Imbalance volumes counted per thermal generating unit, RES plant or RES aggregator and per retail supplier
Imbalance volumes: difference between the Final Position and the metered quantities (excluding quantities under TSO dispatch orders)
TSO dispatch orders under the BM are deemed as instructed deviations
Single pricing settlement
In the beginning, BRPs to undertake financial responsibility of their group under netting of cash flows arrangements. In the future netting of BRPs volumes to be allowed
Balancing energy activated in the opposite direction (than that of the system) is paid (or paying) the marginal price of its direction whereas the rest of the market pays (or is paid) the marginal of the main direction
The deficit or surplus created at the MO's account to be netted at the end of the month and charged/credited to suppliers

10. RES plants operation

Renewable Energy Sources (RES) are becoming an important diversified energy source for electricity generation in the isolated system of Cyprus which for the time being is run only with imported fuels. RES penetration is therefore expected to increase over the years and acquire a significant part in the years to come.

Considering the intermittent nature of RES as well as the limited conventional units' portfolio currently available in the system, the Net Pool Design faces an critical challenge: to allow smooth but substantial RES penetration without jeopardizing system security and without further increasing (the already high) electricity tariffs for end consumers.

It is therefore critical for the market design issued by CERA to identify in details the role of RES and provide for appropriate arrangements that address the above concerns.

CERA has been requested to issue licenses for RES plants that wish to enter the market under commercial terms. There are therefore RES plants operators who wish to enter the market without receiving any support under the NGPs, on the basis that corresponding investments are competitive to the existing system LRMC.

In parallel, a number of RES plants are already operating in the Cypriot system, receiving a FiT under the so called National Grants Plans (NGPs). A few more have already contracted and secure a FiT for the next 20 years but are still on construction or development stage.

The arrangements proposed under the Net Pool design are addressing the above two categories differently, on the assumption that the existing terms of the RES plants operating under NGPs should not substantially change while corresponding support schemes should smoothly cease to exist and therefore the market should be designed to provide no obstacles for commercial RES operation, revealing at the same time the total current costs of electricity generation with a view to allowing RES entry on a competitive basis.

RES curtailments during a first period are only allowed for system security reasons. Taking into account that the TSO procures appropriate reserves capacity availability (both upwards and downwards) there will be few, such cases. In such an event the RES operators are not compensated and the TSO issues a report describing and justifying its decision to curtail RES output.

10.1 New RES power plants operating outside National Grant Plans (NGPs)

New RES generators with installed capacity above 1 MW may either:

a) directly participate into the market on a per plant basis or

b) be represented by an aggregator.

Operators of such plants may choose to bilaterally trade their output or trade it through the DAM or both. Participation to the DAM will be possible through priced Orders (Offers).

New RES generators with installed capacity below 1 MW as they cannot offer energy quantities, on a half hourly basis, greater than 0,5 MWh shall be represented by an aggregator.

In case of direct participation, RES operators should forecast their output per plant and may opt to trade all their forecast quantities in the DAM. In case though they hold bilateral contracts, they should nominate relevant quantities at the OTC registration platform by 9:00 EET on D-1. RES operators wishing to also participate in the DAM, should submit priced orders for the residual quantities.

The quantities selected by the DAM algorithm will receive the DAM clearing price.

The arrangements for the operation of an aggregator are differentiated. For market monitoring reasons an upper limit of [20] MW and a lower limit of [1] MW is imposed to the total size of RES installations that an aggregator could gather under its portfolio. The aggregator should submit a cumulative forecast and pay imbalances based on the total metered quantities of the RES plants it represents. This means that the aggregator, for imbalance settlement purposes, will hold one RES Generation account with multiple RES injection metering points registered within it. The imbalances of RES aggregators will be calculated on the basis of the total injected energy as this is registered at the corresponding meters represented by the aggregator. The settlements between the RES aggregator and the RES plant owners do not fall under the scope of the market design.

In case the RES plant operator (or the RES aggregator) is metered to lower than the OTC and DAM position quantities (final position) then the RES operator (or the RES aggregator) has to pay the imbalance price for the quantities for which it was found short.

If though metered long (compared to its final position), under the imbalance settlement arrangements, the RES operator (or the RES aggregator) should receive the imbalance price for the spill quantities.

It is clarified that imbalances are counted based on the half-hourly metered quantities registered by each plant, even in the case of aggregators. Therefore, all new RES plant wishing to operate outside the NGPs should carry adequate metering equipment.

It is further clarified that in cases of RES plants offering balancing energy the corresponding dispatch orders issued by the TSO do not constitute imbalance.

For very small RES installations below [20] kW the possibility for indirect participation to the market is also allowed through retail suppliers who will undertake to incorporate corresponding output within their portfolio as negative load and therefore for such installations no telemetering equipment will be required.

10.2 RES power plants under National Grant Plans (NGPs)

RES power plants under NGPs that are currently contracted with EAC could either be transferred to a third entity called "RES Agent" as proposed by the LDK-E-Bridge study or could remain under EAC.

In case a RES Agent undertakes the responsibility of representing corresponding operators towards the market, then inevitably this means that the RES Agent will have to pass corresponding quantities through the DAM as must run, as the RES Agent serves no demand to match these quantities outside the DAM.

If a RES Agent is created, tasked with the responsibility to pass corresponding RES quantities through the DAM and receive the Day Ahead clearing price, CERA will have to oblige the Dominant Participant to trade at least equal quantities out of its consumption needs through the DAM. I.e. in case a RES Agent is created, the regulated percentage of the Dominant Participant's Demand Order in the DAM should be increased to cover the RES under NGPs' injection.

During the market design process the details of creating a RES Agent have been studied and important obstacles were identified related to its expected operation, including concerns over the forecast capabilities that the corresponding entity should hold to perform this role.

Technical obstacles were also identified, mainly related to the fact that some of the small RES pants, operating under NGPs, do not hold half-hourly metering capabilities and are only cumulatively metered on a longer period basis. This finding creates obvious obstacles a) as to the imbalance settlements and calculations that would have to take place and b) as to the amounts to be credited/ charged to the RES Agent's account who would undertake corresponding responsibility towards the MO and the TSO of Cyprus.

As an alternative, the possibility to leave the management of RES plants under NGPs with EAC (mandatorily the small ones), under the current contractual status, is proposed. Two alternatives have been identified and examined with a view to simplifying corresponding processes:

a) EAC to manage the total of RES under NGPs under its demand portfolio (independently of their size) in which case EAC would have to forecast the total of their input and handle them as negative load or

b) Create a RES Agent who will only undertake RES under NGPs above 1MW. In this case corresponding quantities will have to pass the DAM as must run.

The first alternative is the simplest one however, is difficult in terms of regulatory supervision. Considering that EAC is a company to be monitored and regulated by CERA for some years to come, CERA might not approve such a substantial generation input to be declared as negative load.

The second approach requires the complexity of creating an entity to undertake corresponding role.

Based on the above two observations an intermediate solution is proposed. The proposal is for EAC to undertake the total of the RES under NGPs but be subject to different arrangements towards their generation depending, on the corresponding RES plant size. It is clarified that EAC Supply[40] undertakes the responsibility to submit corresponding Physical Delivery Nominations matched with appropriate Physical Offtake Nominations. Furthermore, corresponding imbalances are charged/credited to EAC Supply.

It is recognized that the proposed arrangement provide for a substantial complexity as to the RES under NGPs management by EAC[41] but it is expected that this complexity will not be a problem for the Dominant Participant. On the other hand the proposed arrangement bears the advantage that when RES under NGPs (the largest) are individually managed, it will be easier to pass corresponding obligations to other suppliers[42] or assign their management to a RES Agent, in case EAC loses significant market share.

The detailed design of such an approach within the Net Pool Arrangements is described in the paragraphs below.

The energy produced by these plants is expected to replace production by the most expensive conventional units of EAC. Possibly, and due to the limitations of the system operation, the energy produced by RES plants under NGPs replaces also, in some cases, production by the more economic EAC conventional units. Considering that the cost for EAC to purchase corresponding quantities is the average avoided cost, such an arrangement is considered as not creating any extra costs for the company, at least as far as it concerns the replaced energy.

In accordance with ACER Framework Guidelines on Electricity Balancing "The Network Code on Electricity Balancing shall impose that generating units from intermittent renewable energy sources do not receive special treatment for imbalances and have a BRP, which is financially

[40] The option to apply the corresponding obligation to EAC Generation has been examined. Two issues were identified. First, for unbundling of accounts purposes, EAC Generation will have to include within its accounts the cost/profit from corresponding imbalance settlements and other market charges as well as the expense related to the payments made to the RES Fund. Secondly, if the obligation is applied to EAC Generation then it will not be symmetrical in the future to apply similar obligations to other suppliers acquiring significant market share. The approach of applying the obligation to suppliers fits better with the approach of treating RES under NGPs as a social obligation born by all electricity consumers.

[41] EAC will have to split its load with a view to nominating adequate segmented offtake quantities under the OTC registration platform respecting by the same time the DAM participation obligation imposed to it.

[42] In such a case, the expense that other suppliers would have to bear for "purchasing" this RES output would be regulated on the basis of an average wholesale price as the latter is revealed through the DAM

responsible for their imbalances". The management of corresponding quantities as well as the financial responsibility for the imbalances created by RES plants' operation is proposed to be handled as described in the following pages.

10.2.1 RES plants ≥ 1 MW operating under NGPs

Either connected to the transmission or the distribution system RES operators of this category, should submit on a day-ahead basis generation forecasts for the next day (corresponding statements should be filed at the TSO's control centre and copied to EAC).

The above arrangement which imposes penalties to RES plants operators under NGPs[43] in case of forecasts outside specific tolerance limits (tolerances may vary depending on RES plants installed capacity) is proposed to be introduced when the market starts operating under the new design. It is therefore expected that the new MR as well as the significantly modified TDR to be approved by CERA will foresee and describe in details the tolerances as well as the exact penalties to be applied for RES (operating under NGPs) forecasts.

Under current arrangements the revenue from these penalties is directed to the RES Fund to reduce respectively the RES fee paid by the Cypriot electricity consumers. To avoid creating new processes it is proposed that the existing arrangements of directing corresponding amounts to the RES fund is also maintained.

RES plants of this category under the proposed net pool arrangements are considered to comprise part of the bilateral OTC contracts maintained by EAC Supply, meaning on D-1, the latest by 8:00 EET, EAC should submit:

a) appropriate Physical Delivery Nominations per RES plant and
b) matching Physical Offtake Nominations.

EAC when submitting Physical Delivery Nominations for these RES plants may choose to utilise the forecasts provided by corresponding operators under their existing obligation to submit day-ahead forecasts or use its own forecasts. For this reason the gate closure provided by the TDRs for RES plants operators' (operating under NGPs) forecasts submission should be coordinated with the OTC registration platform gate closure.

As per the existing arrangements, EAC payments to RES plant operators of this category are based at the "avoided" cost for the actually metered quantities. The difference with the feed in tariff is charged or credited to the RES Fund.

The Market Operator should hold separate generation accounts per plant of this category. This is required with a view to allowing for concreate imbalance volume settlements based on meter data per plant.

[43] This arrangement is not applied to RES plants operating outside NGPs

In case a RES plant of this category is metered to lower than the OTC nominated quantities then the corresponding account created under EAC will be charged the imbalance price for the "short" quantities. If though metered long (compared to the OTC platform levels nominated by EAC) then the corresponding account should receive the imbalance price for the spill quantities.

The costs gathered to these accounts with respect to imbalances of RES plants >1 MW operating under NGPs should be handled by EAC as the Supply arm of the company exploits corresponding differences. EAC pays the RES operators under NGPs the metered quantities. In case the actual injection is short, EAC Supply pays the avoided cost for less quantities therefore it is fair for EAC to bear the imbalance cost calculated in this case. On the contrary if the RES plants are spilling, EAC pays them the avoided cost for increased quantities therefore it is fair for EAC to keep the spilling income.

By the time an independent supplier acquires a substantial market share (as this will be determined by CERA) CERA may impose it an obligation to undertake adequate part of the RES plants of this category under the above described terms.

The settlement of the energy produced by RES plants in this category is affected by the accuracy of the forecasts upon which corresponding quantities are nominated to the OTC platform. EAC pays RES Fund the regulated "avoidance cost" for the really injected quantities while EAC is respectively credited or charged the imbalance price for the quantities differing the forecast. EAC, as an undertaking with a dominant position, has the ability to efficiently manage this process with a view to minimizing its risk. CERA should monitor RES forecasts, as nominated by EAC, as systematic under-nominations should be avoided. EAC has an incentive to under nominate output from RES plants under NGPs in order to benefit from the expected higher imbalance prices in relation to the avoidance costs the company pays for the excess quantities. It is noted that the design provides (and it should provide) a significant disincentive to the undertaking holding a dominant position with a view to preventing it from taking advantage of the above process and exercising strategic behaviour in the market. The disincentive is provided through charging for some types of operating reserves availability on the basis of the imbalances occurring at the wholesale level. This way the imbalances registered for RES plants in this category (regardless of direction and without netting) are also taken into account.

10.2.2 RES plants operating under NGPs below1 MW holding half-hour metering capability

Since RES plants of this category have the possibility of half-hourly metering, it is proposed that EAC is collectively forecasting their generation and registers them at the OTC platform as **one** virtual RES plant above > 1 MW i.e. one Physical Delivery Nomination is placed on their behalf combined with one matched Offtake Nomination. Similarly to the RES plants≥1 MW, EAC will be responsible for the corresponding imbalances which will be attributed to EAC based on half-hourly metering.

The above design is based on the assumption that all RES plants in this category operating under NGPs are capable of transmitting metering data to the TSO, either directly or through the DSO, on a half-hourly basis.

Obviously, the above comment regarding monitoring and controlling EACs Physical Delivery Nominations for corresponding RES output forecasts, also applies in this case.

10.2.3 RES plants operating under NGPs without half-hour metering capability

Due to its size at the demand side, it is expected that EAC will be capable of managing these quantities along with its demand portfolio. Within this frame, no forecast obligations should apply to RES plants operators of this category.

To allow EAC to better exploit all synergies emerging out of this obligation, EAC will forecast corresponding generation cumulatively and take it into account as negative load i.e. its offtake nominations at the OTC platform and Demand Orders in the DAM should be netted with forecast injections for RES plants in this category.

EAC Supply is therefore responsible for the total (netted) consumption it nominates which incorporates the imbalances from RES plants[44]' injections.

The above arrangements are proposed because the imbalance caused by the operation of the RES plants in this category (in some cases) cannot be measured separately and therefore any benefit or burden caused to the EAC Supply cannot be assessed and remunerated, at least on the basis of accurately measured quantities. In any case EAC is paying corresponding operators the "avoided cost" for the actually metered quantities and therefore is acceptable for EAC to bear the relevant imbalance cost /benefit.

10.3 Self-producers and net metering

CERA has issued decisions 913/2013 and 908/2013 with regard to RES self-producers and PV net metering at households. Under these decisions, the PSO charges as well as the TSO and RES fees are attributed to the total of the consumption (i.e. both to the excess quantities supplied by the grid and to the quantities covered by self-production). TUoS and DUoS are partially charged to gross consumption. Ancillary services including operating reserves are charged to the excess quantities supplied by the Grid and partly to the quantities covered through self-production.

Under the Net Pool Design, operating reserve costs are handled at the wholesale level, therefore corresponding charges should be separated in CERA's decision. For EAC though, as even the costs from its wholesale activation are regulated, those charges should continue being approved by CERA. The proposal though is to distinguish between the two (i.e. operating reserves and other types of ancillary services) for transparency reasons.

[44] RES plants of this category

Above CERA decisions, which as for the time being refer to tariffs provided by EAC, should not apply to competitive suppliers unless modified. Above decisions regulate at the retail level, cost elements that belong to the competitive wholesale component of suppliers, such as costs related to generation fixed costs, long term reserve costs and imbalance and operating reserve costs. As far as independent suppliers are concerned retail tariffs accommodating such costs should not be fixed by CERA but instead should be freely determined by each supplier.

In case the supplier contracted with RES self-producers and household PV net metering installations is EAC Supply, then corresponding costs (portions of EAC's generation fixed costs, imbalance and operating reserves costs) could be regulated and set by CERA at the retail level. Therefore, charges relevant to generation fixed costs, imbalance and operating reserves defined within CERA decisions 909/2013 and 919/2013 apply only in case the supplier is EAC.

Different arrangements for RES operating under NGPs: the existing terms should not substantially change
RES >1 MW operating outside NGPs may either directly participate to the market or through an aggregator
RES < 1MW operating outside NGPs participate through aggregators
An upper limit of [20] MW and a lower limit of [1] MW is placed for the aggregation of RES installations
Aggregators are placing Orders in the DAM (or Physical Delivery Nominations in the OTC registration platform) on a cumulative basis
Aggregators' imbalances are charged per plant (sum)
RES plants operating under NGPs are registered as part of EAC's bilateral contracts and corresponding quantities are not offered through the DAM
Three different categories of RES operating under NGPs are created to handle technicalities
Current CERA decisions about net metering and self-production retail tariffs should apply only in case the supplier is EAC

11. Wholesale transactions

11.1 Charges

Final customers' bills should include two basic components:

- the competitive component and
- the regulated component.

The competitive component is the one freely suggested by each supplier based on the costs each of them faces at the wholesale level (for EAC this component may continue to be regulated for as long as CERA considers that no appropriate competition has emerged).

Suppliers at the **wholesale level** face the following costs:

a) costs related to bilateral energy supply contracts with generators and/or the DAM

b) costs due to imbalance settlements

c) costs related to losses

d) costs related to operating reserves procurement and other system costs

e) dispatch orders to increase consumption by dispatchable load

f) MO account deficit costs

g) expenses related to the supply business operation.

The FRR and RR1 reservation cost is allocated to all market participants proportionally to the imbalances they register. Reservation costs for FCR and RR2 is allocated only to suppliers as system cost. It is clarified that suppliers at the wholesale level are charged quantities which include corresponding system losses.

The regulated component of the retail tariffs is the one which is directly charged on final consumers on a regulated €/MWh or €/MW or both basis following approval by CERA, per customer category. Therefore, the charges comprising the regulated component are the same for consumers of the same category, independently of the supplier serving them. Moreover, a fee is applied and transferred to CERA for each MWh traded. This CERA fee is the same for all customer categories.

The regulated component comprises of the following charges:

i. PSO charges: includes costs related to vulnerable customers[45] and any ad- hoc costs with regard to last resort supply, if activated.[46]

ii. Charges for ancillary services related to black start and reactive power control i.e. excluding charges related to operating reserves which are handled at the wholesale level.

iii. Transmission and distribution (including both medium and low voltage) use of systems charges (under the current status only consumers bear relevant costs[47])

iv. TSO/MO[48] operating costs

v. RES fee.

Initially, suppliers should pay corresponding amounts to the MO on the quantities deemed as served for wholesale settlement purposes and then when metering (and verified) data is available reconciliation should take place. The MO allocates above charges as follows: Amounts related to items i and ii are directed to those entities providing corresponding services. Amounts related to item iii are transferred to EAC on its capacity of the networks owner. Amounts related to item iv are transferred to the TSO and/or the MO. Item v is directly passed to the RES Fund.

It is clarified that retail suppliers charge their customers for the above regulated elements on the basis of metered consumption.

11.2 Wholesale charges imposed by the MO to market participants

Suppliers are charged:

- Costs related to DAM scheduled quantities
- Costs related to network losses (indirectly charged through settlements as per para 12.4)
- FCR, FRR, RR1 and RR2 reservation costs
- costs related to imbalance settlements
- expenses related to dispatch orders towards dispatchable load to increase consumption
- MO account deficit costs (see para 9.5).

Generating units including RES plants operating outside NGPs and RES aggregators are charged:

- costs related to imbalance settlements
- dispatch orders for generation decrease
- FRR and RR1 reservation costs.

[45] According to CERA's amending decision 01/2013 all suppliers are obliged to offer reduced retail tariffs to vulnerable customers and corresponding costs will be reimbursed as PSO through corresponding adjustment of retail tariffs.

[46] It is clarified that if penalties for abusive behaviour are to be returned back to all consumers as per para 12.12, the proposal is that the corresponding amount directly reduces the PSOs.

[47] The new tariff methodology to be issued by CERA continues to apply no G-charge for DUoS and TUoS.

[48] the MO function, if directly levied on traded volumes, should comprise cost element of the suppliers' competitive component

11.3 Wholesale credits paid by the MO to market participants

Suppliers are credited:

- payments related to imbalance settlements
- MO account surpluses (see para 9.5)
- dispatch orders to decrease consumption by dispatchable load
- payments for any operating reserve provided by dispatchable load

Generating units including RES plants operating outside NGPs and RES aggregators are credited:

- DAM income
- payments related to imbalance settlements
- dispatch orders for generation increase
- payments for operating reserves procurement (only for conventional generating units).

The MO charges suppliers for the following components:

- DAM expense
- costs related to losses (indirectly charged through settlements)
- FCR, FRR, RR1 and RR2 reservation costs
- costs related to imbalance settlements
- dispatch orders for consumption increase by dispatchable load
- MO account deficit costs

The MO charges generating units, including RES plants and RES aggregators, for the following components:

- costs related to imbalance settlements
- dispatch orders for generation decrease
- FRR and RR1 reservation costs

The MO credits suppliers for the following components:

- payments related to imbalance settlements
- MO account surpluses
- dispatch orders for consumption decrease by dispatchable load
- payments for operating reserves availability provided by dispatchable load

The MO credits generating units, including RES plants and RES aggregators the following components:

- DAM income
- payments related to imbalance settlements
- dispatch orders for generation increase
- payment for operating reserves availability (only for conventional unist)

12. Other Market Features

12.1 Security Cover Requirements

Energy trading through the Day Ahead Market and the balancing mechanism entails credit risk for the MO against which appropriate security cover should be imposed.

For the Day Ahead Market transactions, as the usual practise is in all trading platforms in Europe, the risk management process is based on a check performed by the MO: each Demand Order submitted by a Market Participant in the DAM should be covered by equal or greater amount of cash collateral. In case the check is negative, the Order is automatically rejected. Such a process should be applied irrespectively of the entity that will undertake the MO role.

With regard to the cash flows settled through the MO for balancing services procurement and imbalances settlement the proposal is the security cover to be calculated on the basis of the corresponding amounts being traded by market participants. Taking into account that there are no trading data available for any other market participants than EAC, nor imbalance prices are calculated for the time being, the market rules should be drafted to reflect the absence of corresponding historical data. Based on this observation the MO should make an approximation of newcomers' exposure to the balancing mechanism for the next two months. The quantities should be approximated based on the trading size of each participant. Following the first two months of activation for a participant, the MO should utilize corresponding actual balancing quantities utilization (net energy purchases) during the past two months in view of accessing the quantities for the next two months. The price to be applied should be the average imbalance price of the previous two months. It is clarified that the security cover should be applied both to generators and suppliers with respect to their net energy purchases through the balancing mechanism.

As the MO serves as the central cashier for the gathering and allocation of various other charges applied to retail suppliers, an extra security cover is proposed to be calculated taking also into consideration corresponding amounts. The security cover may take the form of a bank guarantee or cash collaterals. When there are annual data available regarding wholesale charges imposed by the MO, the latter may proceed in utilizing corresponding annual data to perform approximations of quantities exposure and prices development for the security cover period. It is suggested that the security cover period is set to cover appropriate amount of time (e.g. two months) so that in case of default, the MO will be covered for accordingly sufficient time before resolving the situation. For the first twelve-months of operation of a new supplier the security cover for these charges should be approximated on the basis of the its scheduled trade on a bi-monthly basis (market share). Following a year's activation, the bi-monthly guarantees will be calculated based on the statistical data of the previous year.

The above process (regarding balancing and other system charges security cover calculation) is proposed in case the MO role is assigned to an entity that brings no relevant experience in risk management as the Cyprus TSO. However, in case a clearing house or a bank is involved then the corresponding entity will be held responsible to propose required security covers according to its standards and CERA should approve them or not.

If the MO is in the situation of expelling a market participant because of outstanding debts at the wholesale level then we distinguish between the following cases:

- In case the participant is a supplier, its customers should be transferred to the last resort supplier and its counterparties under bilateral energy contracts should be notified accordingly so as to take appropriate measures against it as defined within their bilateral agreements.
- In case the participant is a generator, its counterparties under bilateral energy contracts should be notified accordingly so as to take appropriate measures as defined within their bilateral agreements. Corresponding suppliers will have to decide whether to continue to provide services to end customers by utilizing the DAM to purchase appropriate energy quantities or submit a request for part or the total of their consumption to be transferred to the last resort supplier. In circumstances where the safe operation of the system is jeopardized, CERA may decide to approve step-in process to the assets of the default generator.

As the market is organized mainly on a bilateral contracts basis, suppliers and generators should freely negotiate and conclude on the security cover suppliers will provide with respect to the energy quantities they are engaged to purchase. Those contracts should include specific terms and procedures on when a party may inform the MO that an energy supply contract has been terminated without the consent of the other party. In the event of a generator denouncing a contract because of supplier's outstanding debts, the MO and CERA should be immediately informed so that the latter will decide whether the supplier may continue to activate using the DAM and any other bilateral contracts it might hold or the supplier is announced in default and has to be expelled from the market. In taking corresponding decision CERA may require the supplier to provide extra security cover to the MO in view of its expected increased utilization of the DAM. In case CERA decides to expel the supplier because its outstanding debts under its bilateral contract jeopardize the smooth market operation, its customers should be transferred to the last resort supplier and its counterparties under bilateral energy contracts should be notified accordingly so as to take appropriate measures against it as defined within their bilateral agreements.

12.2 Market Metering Requirements and Metering profiling

The efficient operation of the market depends on the availability of verified data on energy flows into and out of the system. This requires metering equipment of suitable accuracy and reliability, providing the data needed for market settlements (as well as other charges).

Each retail supplier should submit meter representation authorization when it contracts with a customer. The TSO and the DSO as appropriate should keep a corresponding Registry with all metering points in their networks which shall be continuously updated with representation data (copied also to the MO).

There is adequate per half-hour metering installed at all Transmission System boundaries. However, at the distribution level many consumers' meters are only registering aggregated data (non-interval meters). This is also the case for the output of some small embedded RES generating plants.

Under the proposed design, suppliers should be settled for each settlement period according to their actually metered quantities. However, there are cases where actual metering data is available only after the settlement process takes place and in many cases only cumulative quantities are registered. Profiling of metering data should be applied with a view to allowing competition to work even in cases where non-interval metering exists.

Specifically, the Distribution System Operator is proposed to forecast the total of the non-profiled meters for the next month and determine ex-ante and on a monthly basis, representation percentages of each supplier on the basis of historical data for the meters represented by each of them. As the DSO holds consumption profiles per half hour period for various consumer categories, the representation percentage for each supplier will be calculated on the basis of corresponding profiles and in proportion to the categories of consumption the supplier is representing. However, for such a methodology to be applied, the DSO should in addition hold appropriate data of small RES plant output on a half hour basis and per technology. Such data is required in cases where other suppliers (outside EAC) incorporate small RES output within their portfolio under the negative load approach and therefore the effect of such output to their profile should be somehow accessed. In any case the representation percentage for EAC Supply is always calculated based on the residual quantities.

The estimated percentage of each supplier is then applied to the half-hourly actually metered quantities entering the distribution system (excluding the quantities at the distribution level for which there is half-hour metering data available and adding the embedded generation). The outcome comprises the quantities for which each supplier will be settled under the market rules for consumption quantities represented by it corresponding to non-interval metering.

If the metered data is missing or erroneous, the TSO/DSO shall make their best estimate of the 'true' value.

12.3 Reconciliation of Metering Data

Reconciliation should take place as soon as actual metering data is gathered. Since accumulated metered data will be available, the DSO can only calculate, for each supplier, the real representation percentage for the corresponding period. The DSO, following the ex-post calculation of the representation percentages, will forward corresponding data to the MO. For all settlement periods of the period for which updated representation percentages apply, the MO will apply the updated figures to the metered quantities entering the distribution system (excluding the quantities at the distribution level for which there is half-hour metering data available and adding the metered embedded generation). The difference between the quantities calculated by applying the estimated representation percentage and the real representation percentage per half-hour for each supplier will be credited or charged at the corresponding imbalance price.

12.4 Losses Management

Losses is proposed to be handled as per the existing market rules under which corresponding quantities are indirectly taken into account within the settlement between metered and contractual quantities applied to suppliers (through the use of a transmission and distribution losses multiplier applied under the Transmission and Settlement Rules).

In the OTC registration platform, retail suppliers should adjust their volumes accordingly so as to purchase the increased quantities needed to cover losses as per the above losses factors. Similarly in the DAM process, the volumes of Demand Orders should be accordingly adjusted. To facilitate market participants, the TSO and the DSO will ex-ante and at least one month in advance publish an estimation of the transmission and distribution system losses (medium and low voltage losses will be indicated sedately).

When actual metering data is available the MO should take into account the real losses in calculating suppliers' imbalances (reconciliation). The TSO and DSO should pass real losses data to the MO.

A clarification should be added within the Market Rules that the Distribution Loss Factor applied to Suppliers consumption should only reflect the medium voltage losses (and not the total distribution losses of the corresponding zone) in case of suppliers representing only customers at the medium voltage. For suppliers representing customers both at the medium and the low voltage a losses factor appropriately weighted should be applied.

12.5 Communication

The exchange of information between participants, the MO and the TSO (including submission of registrations, DAM Orders submission, reserves offers submission, balancing energy bids/offers submission, notification of results and schedules defined under the DAM) takes place by exchanging appropriate files through the Internet or by filling in appropriate forms available on the MO's and the TSO's websites (web forms).

The market information system is controlled from the trading room of the MO, which is equipped with hardware and software components permitting it to collect and process the transactions and schedules registered on the DAM and the OTC registration Platform.

The MO should furthermore be equipped with hardware and software components permitting it to receive offers for operating reserves commitment; as well as bids and offers for balancing energy placed by market participants and communicate them to the information system of the TSO.

The MO personnel should ensure the continuous operation of the system under maximum security conditions and provide support to market participants.

Similarly, the ISP and the real time balancing mechanism are controlled from the control room of the TSO, which is equipped with hardware and software components permitting it to collect and process the corresponding transactions and issue dispatching orders. The TSO personnel should ensure the continuous operation of the system under maximum security.

The TSO should transmit the results of the BM to the MO for settlement purposes.

12.6 Market Data Reporting

The EU Regulation for Energy Markets Integrity and Transparency known as REMIT sets out the details and type of data to be reported by market participants, the TSO and the MO included, to the CEREMP[49] platform run by ACER (data is copied to competent NRAs).

CERA following the publication of the Implementing Regulation for REMIT (Regulation 1623/2014) on 17/12/2014, which sets the dates for market participants' registration and reporting to the CEREMP platform, should undertake to inform and support all market participants (the MO and TSO included) with regard to their registration in the platform and their continuous obligation to report corresponding data.

Transaction and fundamental data submitted to the platform are copied by ACER to CERA and the latter bears the responsibility to investigate any case of possible market abuse or manipulation and in case of REMIT regulation breaches, CERA should impose corresponding fines.

12.7 Market Data Publishing

The Commission Regulation (EU) No 543/2013 of 14 June 2013 on submission and publication of data in electricity markets mandates a minimum common level of data transparency through publication of data on a non-discriminatory way. In this respect, one central information platform, managed by ENTSO-E, has been created to provide all market participants with a coherent and consistent view of the market. TSOs, and where appropriate MOs, are obliged to submit specific data on this platform.

Although Cyprus is not interconnected, the TSO of Cyprus should follow the data collection and publication rules enforced through the above mentioned EU Regulation and therefore the information system to be procured should take corresponding requirements into account. Data

[49] Central European Register for Energy Market Participants

should at least be uploaded to the TSO's website and in time adequate interfaces should be developed to allow transmission to the ENTSO-E transparency platform.

In summary, EU Regulation 543/2013 foresees for the following data collection and publication:

- Information on national load per market time unit (e.g. half-hour) to be published ex-post
- Day-ached forecast of total load per market time unit to be published at least 2 hours before DAM gate closure and be updated afterwards
- Week, month and year ahead aggregated load forecasts to be published ex-ante
- Information relating to the unavailability of transmission infrastructure to be published no later than one hour after the change in availability
- Information relating to congestion management measures, if any
- Forecast of total generation
- Forecast of wind and solar power generation (MW) per each market time unit of the following day (RES units, above a threshold, to submit the TSO corresponding forecasts)
- Information relating to the unavailability of generating units
- Actual generation per market time unit (separately for Wind and Solar-profiled where no data is available)
- The amount of balancing reserves under contract (MW) by the TSO
- Prices paid by the TSO per type of procured balancing reserve and per procurement period (Currency/MW/period)
- Accepted aggregated offers per half-hour, separately for each type of balancing reserve
- The amount of activated balancing energy (MW) per half-hour and per type of reserve
- Prices paid by the TSO for activated balancing energy per half-hour and per type of reserve, price information shall be provided separately for up and down regulation
- Imbalance prices per half-hour
- Total imbalance volume per half-hour;
- Monthly financial balance

The exact publishing timing of above elements should follow the Regulation provisions.

There will be an obligation on the MO to publish at least the following market information (subject to appropriate confidentiality issues), and to maintain an archive of this information for [5] years, accessible to all Market participants and other interested parties:

- Aggregated volumes of the OTC registration platform per half-hour(to be published at least 1 hour before the DAM gate closure)
- Aggregated volumes of RES under NGPs registered at the OTC platform per-half period (to be published at least 1 hour before the DAM gate closure)

- At least aggregated volumes per type of technology (conventional, solar wind) scheduled under the DAM per half-hour
- The DAM clearing price per half-hour and the DAM volumes scheduled for each market participant per half-hour.

This information shall be provided in Greek, at least, and shall be made available in an efficient manner and gathered in a single interface.

12.8 Invoicing and Cash Collection

This section describes the timetable and procedures to be followed by the MO in issuing monthly invoices for payments/charges to Trading Parties.

On the [6th] business day of M+1, the MO will prepare the following:

- a notification to be send to each supplier regarding the sum of payables in respect of all Demand Orders accepted in the DAM during the previous month
- a notification to be send to each generating unit regarding the sum of receivables in respect of all Generating Orders accepted in the DAM during the previous month
- a notification for payments to all FCR, FRR and RR1 reserves providers
- a notification to all balancing energy providers (copied to the TSO) regarding their net financial position in respect of the dispatch orders they received during the previous month
- a notification to all BRPs (copied to the TSO) regarding their net financial position in respect of registered, per half-hour, imbalances of the previous month
- a notification to all suppliers as to the uplift charges, network fees and other levies applied for month M.

The above information should be provided to allow market participants to validate the settlement volumes.

On the [20th] business day of M+1, the MO will issue invoices towards:

- each supplier that is debtor to the MO regarding its DAM activation during month M
- each balancing energy provider that is debtor regarding its BM activation during month M
- each BRP[50] that is debtor under imbalances settlement during month M
- each supplier regarding the uplift charges, network fees and other levies applied for month M.

On the [20th] business day of M+1:

- Generators issue invoices towards the MO regarding Generating Orders acceptance during month M

[50] It is clarified that each market participant may be a BRPs itself or sign with a third BRP.

- BRPs issue invoices towards the MO in case they are receivers under imbalances' settlement
- balancing energy providers issue invoices towards the MO in case they are receivers regarding BM activation during month M
- Providers of FCR, FRR and RR1 availability issue relevant invoices to the MO.

In case of disputes over the volumes or other data registered under each market participant, the invoice should be paid and any dispute regarding data accuracy dealt with later.

Where after a dispute it is recognised that there has been an error in a market participant's invoice charge or metered quantity in one or more settlement periods, the MO will determine the adjustments to be made to all market participants' invoices, which may involve re-running settlement calculations for the relevant and any subsequent periods. Any such adjustments will appear as a supplementary item in each invoice at the next invoice cycle.

Payments by market participants to the MO account should be made within [5] business days from the date the invoice has been issued. Payments by the market participants to the MO should precede payments by the MO to market participants to minimise the MO exposure.

The MO should pay market participants within [10] business days from the date corresponding invoices have been issued.

As analysed under section 9.5 the financial sum of all balancing provision actions and imbalance settlements, for the total of market participants and for the same settlement period, might not be zero meaning a residual will sometimes be gathered to the MO account. The corresponding cost or surplus is proposed to be socialised as per para 9.5.

In the event of non-payment of an invoice, the MO should use the security cover for the unpaid amount.

12.9 Emergencies

The procedures whereby the TSO declares a system emergency should be set out in the Transmission and Distribution System Rules. Market Rules though should provide that in the event of an emergency declared by the TSO, the ordinary processes of the market arrangements would be suspended for the duration of the system emergency and administratively defined prices will apply. The Market Rules should also provide that where market participants incur additional costs supporting the TSO in its response to a system emergency, they may recover these costs under justified claims and following CERA's approval. It is clarified that these costs should not be passed to end consumers as PSOs. Those costs occur at the wholesale level and following CERA's approval should be attributed to corresponding market players at the wholesale level, on the basis of their operation during the emergency.

The MO should also set procedures regarding market suspension in case the information system it operates faces major problems such as not being possible to receive, orders, nominations or bids and offers from market participants.

12.10 Market Operator Fee

Under the provisions of the Law, the MO role is assigned to the TSO. Within this frame, the MO's operating costs could be remunerated under a regulated process, along with the TSO operating costs. The regulated process for TSO's operating expenses is provided under the tariffs methodology issued by CERA.

However, in case the MO role is assigned to a legally separate entity within the TSO (e.g. subsidiary), then, it might be simpler to allow for a fee on the basis of traded MWhs. Such a fee is usually directly paid by market participants.

12.11 Market Rules and Manuals

Based on the approved design of the Net Pool arrangements and according to the provisions of articles 79 and 80 of the Electricity Law the MO[51] and the TSO of Cyprus should undertake to draft corresponding Market Rules and modify the Transmission and Distribution Rules accordingly.

Considering that there is no market information system in place and almost all processes should be developed from scratch there are synergies that the total of market arrangements (i.e. the OTC registration platform, the DAM platform, the ISP and the real time balancing process and the imbalances as well as other settlement processes) are developed under a common information system that will provide for the appropriate interfaces between the different segments. However, it is also possible that the MO and the TSO procure their systems separately making sure though that appropriate interfaces are developed.

The proposal is for the Cyprus MO to undertake the procurement of the total of the information systems required under the proposed design and then pass the operation of the platform performing both the ISP and the real time balancing to the TSO. It is clarified though that the MO will undertake all financial transactions and settlements with regard to day-ahead, FCR, FRR and RR1 provision, balancing energy provision and imbalance settlements of market participants. The settlement for reservation of RR2 will be directly managed by the TSO.

Technical processes and details of the market operation should be also included in the manuals that accompany the Market Rules. The manuals should be developed by the MO (and the TSO with regard to the ISP and the real time balancing process) and approved by the regulator.

[51] It is noted that article 80 of the Electricity Law mentions that the TSO issues the Market Rules. In case a third entity is assigned the MO role the corresponding reference within the Law should be modified to provide that the MO issues the Market Rules.

The MO and the TSO should publish the manuals for the operation of the various market segments at their web sites. By the time the information system is finalised and tested corresponding manuals, in their final format, should be approved and published.

As soon as possible and in all cases prior to the market information systems testing, the MO and the TSO should make available all required communication standards and specifications with a view to allowing sufficient time for market participants to develop corresponding tools.

Market rules should develop appropriate formulas as per the current design taking into consideration that the parameters appearing in brackets [ ] will be defined by CERA decisions on a yearly basis.

12.12 Allocation of the penalties income

In several cases the proposed design provides for penalties imposition with a view to preventing abusive behaviour. There are two options for the allocation of corresponding amounts:

- either distributed to the total of consumption e.g. by reducing the regulated PSOs paid at the retail level or
- allocated to those market participants that have suffered from such an abusive behaviour on the basis of an ad-hoc analysis to be performed by the regulator.

The second approach seems to provide market participants with more appropriate signals however, it requires CERA to perform a series of calculations.

For market design purposes the imposition of penalties is important as a disincentive for inappropriate behaviour. To this end the MO should gather, in a separate account, corresponding penalties and CERA, on an ad-hoc basis, should decide on either of the above approaches. All penalties imposed by the MO should have received CERA's approval before being applied. The MO shall prepare an annual report to be submitted to CERA describing in full all penalties imposed and the transfer of funds received.

It is clarified that this paragraph discusses the penalties imposed under the proposed net pool arrangements mainly towards abuse of dominant position.

Demand Orders in the DAM should be covered by equal or greater amount of cash collateral
For all market participants adequate guarantees should be kept corresponding to their BM exposure
Additionally, for retail suppliers adequate guarantees should be kept corresponding to the remaining sector charges besides DAM and BM exposure

A Meters Registry should be created and maintained
For non-interval meters: profiling based on representation percentages
Reconciliation based on cumulative data (representation percentages to be ex-post calculated)
Suppliers' registrations in the OTC platform as well as Demand Orders in the DAM to be adequately adjusted to take into account losses
TSO and MO reporting as per the REMIT requirements
TSO data publishing as per the EU Regulation 543/2013
In case of emergencies market arrangements are suspended
Abusive behaviour is penalized

13. Demand Response

Demand Response will not be applied in the beginning of the market operation as Cyprus is an immature market. However, this Section provides for a brief analysis which demonstrates that the proposed arrangements could, under appropriate additions, accommodate this service in case, in the future, it is considered that such a service provides added value to the electricity sector of Cyprus.

Demand Response is a service that can be provided either by suppliers serving load or by entities (Demand Response Agents) who aggregate smaller retail customers and directly bid corresponding capacity into the wholesale markets. In this respect Demand Response programs run by the DSO could directly participate in the wholesale arrangements as well.

Demand Response Agents should therefore accede to the Market Rules and become market participants.

In case of demand response, corresponding Agents should also be allowed to offer load curtailment at the DAM stage under arrangements that approximate those of generating units' orders. However, since the DR Agent may not coincide with the supplier representing corresponding load, the latter will be also compensated in case of load curtailments i.e. the system will effectively double pay the same service. It is therefore required that the supplier's Physical Position after the DAM closure is appropriately adjusted in case the DR Agent has scheduled a demand curtailment in the DAM. For such an adjustment to be possible, each DR Agent should submit Orders in the DAM per portfolio of meters registered under each retail supplier.

Obviously, by the time DR is activated through the wholesale arrangements, the metering representation Registry should further foresee who the DR Agent is, under each meter.

The DR Agent will receive the DAM price for the curtailed quantities and later should be checked against a baseline. There are several methodologies developed worldwide on how corresponding baselines could be calculated.

The adjustment of the supplier's final position should be made on the basis of the volume approximated by the baseline methodology as actually curtailed.

Similarly the DR Agent should be possible to place offers for demand curtailment at the BM. The design already foresees for suppliers representing large dispatchable load to submit corresponding offers. However in case DR enters the wholesale market then offers to the BM should only be made by one entity: the DR Agent (which though could be the supplier itself). Similar arrangements to those applied when demand response is scheduled under the DAM, apply and in case demand response is activated in the BM.

As ultimately the income from the corresponding service should be passed to the retail customers, the DR Agent and the supplier (in case these are different entities) should proceed with bilateral arrangements which will provide for the income to be reflected in supplier's retail tariffs to end consumers.

For DR to be smoothly integrated within wholesale market arrangements sufficient technical and metering capabilities need to be developed therefore the proposal is that for the moment only dispatchable load participates with offers for demand decrease or demand increase within the BM. However, in a few years the design should accommodate such settlement arrangements that will make possible DR activation by corresponding Agents.

It is clarified that DR Agents may also place offers for FCR, FRR and RR1 availability under the ISP, provided that the corresponding demand holds appropriate technical characteristics allowing it to respond within the time frame set by the TSO for each type of reserve activation.

Demand Response to be allowed to be offered by entities other than the supplier
Demand Response to participate both in the DAM and in the BM

ANNEX A

The following definitions are provided only for the purposes of subject Report:

Balance Responsible Parties: entities that undertake the financial settlement towards the MO with regard to the imbalances registered for a group of market participants as provided under para 9.4.

Balancing Mechanism: a process under which the generation levels of the units are determined for each 30' taking into consideration the bids and offers for balancing energy submitted under the ISP in the afternoon of D-1. Conventional generating units with installed capacity above [5] MW are obliged to participate in the BM for the total of their capacity.

Balancing Services Providers: participants who have the capability to provide balancing services to the TSO. Both balancing reserve and balancing energy are considered to constitute balancing services. During a first phase, such providers include conventional generating units and dispatchable load. RES plants holding adequate technical capabilities may only provide for downwards balancing energy and not the other types of balancing services.

Bids for energy absorption: Within the DAM such bids are mentioned as Demand Orders and exclusively refer to bids placed by retail suppliers. Under the balancing process such bids are also mentioned as downwards balancing energy bids and may be placed either by dispatchable load or dispatchable generating units.

Block Generating Orders: Orders of a special type which are proposed to be allowed in the DAM as they allow generating unit operators to submit offers for energy injection in a way that secures the economic operation of their units while the technical minimum constraint is met.

Commercial Programme: the programme of a market participant as this is determined by the validated Nominations for Physical Delivery/Offtake of the forward market or by the quantities cleared under the DAM or both. In the latter case the commercial program coincides the market participants' final positions.

Day-Ahead market clearing price: The price produced by the DAM algorithm run during D-1 for each 30' of day D (the point where the demand curve crosses the offer curve). All Generating Orders and all Demand Orders being cleared by the DAM are paid and paying the DAM clearing price accordingly.

Day-Ahead Market: A centrally organised market taking place the morning of D-1 within which trading of physical products is performed. This market is mandatory for the remaining capacity of all conventional units above [5] MW installed capacity (as well as for the remaining capacity of smaller conventional units above [1] MW and aggregated per connection point capacity above [5] MW). Participation in this market is optional for retail suppliers and RES plants operating outside NGPs. Generating Orders are separately submitted in relation to Demand Orders.

Demand Orders: bids for energy absorption submitted by retail suppliers to the DAM. For an initial period such orders may be non-priced.

Demand Response Agents: market agents who gather together retail consumers (load) and have the capability to directly submit bids and offers to the wholesale markets for energy injection/ absorption through corresponding response from their consumers. Demand Response Agents can be either retail suppliers or third entities who hold appropriate technical equipment allowing them to manage and control the consumption they represent towards the various wholesale markets and mechanisms.

Dispatch Orders: Orders issued by the TSO towards the generation units and the load that are participating to the ISP and the real time balancing mechanism.

Dispatchable load: load (consumption) holding technical capability to respond to TSO orders. Such load has the option to submit offers for operating reserves availability provided it can meet the technical specifications set by the TSO for each type of operating reserve. The dispatchable load may also, through corresponding retail suppliers, submit bids and offers for balancing energy.

Distribution System Operator: in accordance with the description provided under paragraph 3.4.

Dominant Participant: The Electricity Law in Cyprus makes reference to the term "dominant position". Market Participants can be declared as holding a dominant position in the electricity market if they satisfy the conditions specified in the Competition Protection Law. In accordance with this law an undertaking is holding a "dominant position" when the undertaking enjoys an economic power which makes it capable of preventing efficient competition in the market and allows it to act, on a substantial degree, independently of its competitors and ultimately independently of customers.

Downwards balancing energy marginal price: The marginal price of offers for energy absorption by the BM which have been accepted with a view to addressing real time imbalances.

Final Position: The Final Position of a generating unit is the sum of its validated Physical Delivery Nominations and its accepted Generating Orders in the DAM for every half-hour of the next day. The Final Position of an offtaker is the sum of its validated Physical Offtake Nominations and its accepted Demand Orders in the DAM for every half-hour of the next day.

Forward Market: a market organised on a bilateral basis. The forward market is a market where participants are freely trading energy quantities. However, CERA may apply a regulated process for the forward contracts of the dominant participant.

Generating Orders: offers for energy injection submitted by generating units to the DAM. These Orders may be simple half-hour orders with maximum 10 pairs or block generating orders.

Imbalance Price: When the system is in deficit (short), the imbalance price of the corresponding half-hour is determined by the upwards balancing energy marginal price, as this is calculated under the real time balancing optimisation process. When the system is in excess (long), the imbalance price of the corresponding half-hour hour is determined by the downwards balancing energy marginal price, as this is calculated under the real time balancing optimisation process.

Integrated Scheduling Process: A central process which is operated by the TSO in the afternoon of D-1 with a view to securing a technical feasible unit commitment and procuring operating reserves under the most economic efficient way. Details of the process are provided under para 7.4.

Intra-day Market: a centrally managed market taking place after the day- ahead market clearance which can operate close to real time. An intra-day market might be operated based on auction sessions or on a continuous basis.

Market Operator: in accordance with the description provided under para 3.4.
Offers for energy injection: Within the DAM such bids are mentioned as Demand Orders and exclusively refer to bids placed by retail suppliers. Under the balancing process such bids are also mentioned as downwards balancing energy bids and may be placed either by dispatchable load or dispatchable generating units.

Operating Reserves: Operating reserves include the Frequency Containment Reserve, the Frequency Restoration Reserve, the type 1 Replacement Reserve and type 2 Replacement Reserve as these are defined in paragraph 7.2.

OTC Platform: software that runs through the web allowing the registration and validation of OTC contracts of market participants and their subsequent modification to Physical Delivery Nominations and Physical Offtake Nominations.

Physical Delivery Nominations: Nominations submitted to the OTC platform by generators (RES plants and RES aggregators included) in the morning of D-1regarding the energy quantities they have contracted to generate during day D.

Physical Offtake Nominations: Nominations submitted to the OTC platform by retail suppliers in the morning of D-1 regarding the energy quantities they have contracted for utilization during day D.

RES aggregators: entities which undertake to cumulatively represent small RES plants operating outside NGPs towards the MO and the TSO. The cumulative capacity they can represent has a lower limit of [1] MW and upper limit of [20] MW.

Retail Suppliers: entities which enter into retail contracts with end customers for the supply of the latter with electricity. Retail suppliers represent their customers to the wholesale markets through the corresponding physical offtake points.

Transmission System Operator: in accordance with the description provided under paragraph 3.4.

Upwards balancing energy marginal price: The marginal price of offers for energy injection to the BM which have been accepted with a view to addressing real time imbalances.

Wholesale Suppliers: entities which purchase and sell electricity quantities without having signed any contract with final customers. These entities do not represent physical offtake points.

ANNEX B

Block Generating Orders

A block Generating Order is an Order defined by:

- a fixed price limit (minimum price for generating block),
- a number of periods,
- a volume that can be different for every period, and the
- minimum acceptance ratio.

In the simplest case, a block is defined for a consecutive set of periods with the same volume for all of them and with a minimum acceptance ratio of 1 (regular "fill-or-kill" block orders). These are usually called regular block orders. However, in general, the periods of the blocks can be non-consecutive, the volume can differ between periods and the minimum acceptance ratio can be less than 1 (partial acceptance).

Acceptance of the Generating Block Orders is based on the following principles:

- in case the block volume weighted average market clearing price for the periods during which the block is defined is above the price of the block, then the block can be entirely accepted, which means that all the energy in the block is accepted;
- in case the block volume weighted average market clearing price for the periods during which the block is defined is below the price of the block, then the block must be entirely rejected;
- in case the block volume weighted average market clearing price for the periods during which the block is defined is exactly the price of the block, then the Block can be either fully rejected, fully accepted or partially accepted, to the extent that the ratio "accepted volume/total submitted volume" is greater than or equal to the minimum acceptance ratio of the block and equal over all periods.

Block orders can be linked together (Linked Block Orders), i.e. the acceptance of individual block orders can be made dependent on the acceptance of other block orders. The block which acceptance depends on the acceptance of another block is called "child block", whereas the block which conditions the acceptance of other blocks is called "parent block".

The principles for the acceptance of linked block orders are the following:

- The acceptance ratio of a parent block is greater than or equal to the acceptance ratio of its child blocks
- Possibly partial acceptance of child blocks can allow the acceptance of the parent block when:

- the surplus of a family is non-negative
- block orders without child blocks do not generate welfare loss

- A parent block which is out-of-the-money can be accepted in case its accepted child blocks provide sufficient surplus to at least compensate the loss of the parent
- A partially accepted child block must be at-the-money if it has no parent blocks that are accepted
- A child block which is out-of-the-money cannot be accepted even if its accepted parent provides sufficient surplus to compensate the loss of the child, unless the child block is in turn parent of other blocks (in which case rule 3 bullet applies).

Abbreviations Table

ACER	Agency for the Cooperation of Energy Regulators
AS	Ancillary Service
BM	Balancing Mechanism
BNE	Best new Entrant
BRP(s)	Balance Responsible Party(ies)
BSP	Balancing Service Provision
CACM NC	Capacity Allocation and Congestion Management Network Code
CERA	Cyprus Energy Regulatory Authority
CEREMP	Central European Register of Energy Market Participants
CfDs	Contract for Differences
CSP	Central Scheduling Process
DAM	Day Ahead Market
DR	Demand Response
DSO	Distribution System Operator
DUoS	Distribution Use of System
EAC	Electricity Authority of Cyprus
EB	Electricity Balance
EB NC	Electricity Balancing Network Code
EET	Eastern European Time
ENTSO-E	European Network of Transmission System Operators for Electricity
FCA NC	Forward Capacity Allocation Network Code
FCR	Frequency Containment Reserves
FG	Framework Guidelines
FiT	Feed-in Tariffs
FRR	Frequency Restoration Reserves
GME	Gestore Mercati Energetici –The Italian Market Operator
IDM	Intra Day Market
IPP	Independent Power Producers
ISP	Integrated Scheduling Process
MECIT	Ministry of Energy Commerce, Industry and Tourism

MO	Market Operator
MR	Market Rules
NC	Network Codes
NGPs	National Grant Plans
NRA	National Regulatory Authority
OTC	Over the Counter
PCR	Price Coupling of Regions
PSO	Public Service Obligations
REMIT	Regulation (EU) 1227/2011 on wholesale energy market integrity and transparency
RES	Renewable Energy Sources
RR	Replacement Reserves
SGCY	Support Group of Cyprus
TDR	Transmission and Distribution Rules
TSO	Transmission System Operator
TUoS	Transmission Use of System
VoLL	Value of Lost Load