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संदर्भ संख्या: पोसोको/एनएलडीसी/2020/ **दिनाँक**: 14th August, 2020

सेवा मे,

Secretary
Central Electricity Regulatory Commission
3rd & 4th Chanderlok Building 36,
Janpath Rd, New Delhi, Delhi 110001

विषय: POSOCO Suggestions on Draft Central Electricity Regulatory Commission (Power Market) Regulations, 2020

संदर्भ: Public Notice No. L-1/257/2020/CERC dated 18th July, 2020 on Draft Central Electricity Regulatory Commission (Power Market) Regulations, 2020.

महोदय,

With reference to above, the POSOCO Suggestions on Draft Central Electricity Regulatory Commission (Power Market) Regulations, 2020 are enclosed herewith for kind consideration.

सादर धन्यवाद,

भवदीय,

14/8/2020

(S S Barpanda)
Director (Market Operation)

संलग्न: As above

Draft CERC Power Market Regulations, 2020
Suggestions on behalf NLDC and RLDCs

Dated: 14th August 2020

The draft regulations are intended to cater to increasing depth in the Indian electricity market. The introduction of forward contracts on Power Exchanges with mandatory physical delivery would give another avenue for competition in all types of contracts i.e. short term, medium term and long term with hedging and risk mitigation opportunity. The introduction of regulatory provisions for OTC platforms would allow the introduction of technology driven platforms which would serve as a common meeting ground for OTC transactions, price discovery and transparency in the OTC market.

The introduction of concept of Market Coupling Operator is a major reform which would facilitate a uniform price discovery across the country while retaining the freedom and choice to the buyers/sellers for participation on any of the Power Exchanges. Power Exchanges would also have to compete on support and value-added services to their members/clients.

The increase in the net worth requirement for the entities to setup the Power Exchanges would ensure that only serious players with well thought business plans would venture into setting up of power exchange. The tightened ownership and governance norms for Power Exchanges, with enhanced market oversight by CERC are in positive direction as the volumes and participation ramp up through power exchange platforms in near future.

The suggestions on behalf of NLDC/RLDCs are presented in the following sections:

Clause-wise inputs

A. Definition of Contingency Contract and Intraday Contract

In the Draft Power Market Regulations 2020 (hereinafter draft PMR, 2020), Part – 1, Clause 2: Definitions and Interpretation, the definition of Contingency Contract and Intraday Contract is as follows:

(a) "Contingency Contract" means a contract wherein Continuous Transactions occur on day (T) after the finalization of day ahead transactions and the delivery of electricity is on the next day (T+1);

(ab) "Intraday Contract" means a contract wherein Continuous Transactions occur on day (T) and delivery of electricity is on the same day (T), such that its delivery period does not overlap with the specified delivery period of the Real-time Contract transacted in the same bidding session as that of the Intraday Contract;

In the extant Power Market Regulations 2010 (hereinafter PMR, 2010), the definition of Intra-Day Transaction /Contingency Transaction, which is also consistent with Open Access in Inter-state Transmission (6th amendment) Regulations 2019, is as follows:

"(ga) "Intra-Day Transaction / Contingency Transaction" means the transaction (not being a collective transaction) which occurs on day (T) after the closure of day ahead market window for delivery of power on the same day (T) except for the duration of the specified period of delivery of the real-time market, or for the next day (T+1) and which are scheduled by Regional Load Despatch Centre or National Load Despatch Centre."

As per the above definition given in 2010, any 'bilateral transaction' that was done after closure of the DAM for delivery on the same day or next day were called inter-day/contingency transactions.

As per the above, the draft PMR, 2020 has divided the intra-day and contingency transactions and re-defined with two separate definitions on the basis of day of delivery. Therefore, the definitions of the contracts in the draft PMR, 2020 may be modified to be in consonance with the extant Open Access Regulations for better clarity to all stakeholders.

B. Definition of Real Time Contract and Concept of Gate Closure

In the draft PMR, 2020, Part – 1, Clause 2: Definitions and Interpretation, the definition of real time contract is as follows:

"Real-time Contract" means a contract other than Day Ahead Contract or Intraday Contract or Contingency Contract, wherein Collective Transactions occur on day (T) or day (T-1) and delivery of electricity is on day (T) for a specified delivery period;

In the extant PMR, 2010, the definition of Real Time Contract, as per Second Amendment in 2019, is as follows:

"(cca) "Real-time Contract" means the contract other than day ahead contract and intraday or contingency contract, where collective transactions occur on the day (T) or (T-1) after the right to revision of schedule ends for a specified delivery period during the day (T) and which are scheduled by Regional Load Despatch Centre or National Load Despatch Centre."

The introduction of gate closure is a systemic reform in the Indian Electricty Market. A joint POSOCO-NREL publication under the GtG-MoP program analyzes global experiences with gate closure, and reviews the unique benefits, challenges, and other considerations that will impact the implementation of gate closure in the Indian electricity market.[1] A copy of the publication is enclosed for ready reference.

It is suggested that the definition of Real Time Contract as provided in the Second Amendment to the Power Market Regulations, 2010 may be retained in the proposed

[1] OPENING MARKETS, DESIGNING WINDOWS, AND CLOSING GATES India's Power System Transition - Insights on Gate Closure https://www.nrel.gov/docs/fy19osti/72665.pdf

Power Market Regulations, 2020 as it provides more clarity and has already been implemented.

C. Principles of Price Discovery

In the draft PMR, 2020, Part – 3 Features of Contracts, for the Day Ahead Contracts and Real-time Contracts transacted on Power Exchanges, it has been laid down that

"…(ii) Price discovery mechanism shall adopt the principle of ***maximisation of economic surplus (sum of buyer surplus and seller surplus)****, taking into account all bid types…."*

Further, in regulation 31 on Information Dissemination by Power Exchange in the draft PMR, 2020, it has been provided that

"….(8) Power Exchange shall create and maintain a document on its website providing detailed description of the algorithm used for price discovery for all type of contracts. The description shall include bid types, details of how the algorithm results in ***maximisation of economic surplus*** *taking into account various bid types and congestion in transmission corridor, which shall be updated with every new version of the price discovery algorithm…"*

Also, in draft PMR, 2020, Part –5 Market Coupling, Regulation 37. Objectives of Market Coupling, it has been provided that:

"…(3) ***Maximisation of economic surplus****, after taking into account all bid types and thereby creating simultaneous buyer-seller surplus…."*

Also, in regulation 39. Functions of the Market Coupling Operator, it has been provided that:
(3) Market Coupling Operator shall create and maintain a document on its website providing detailed description of the algorithm used for price discovery. The description shall include bid types, details of how the algorithm results in ***maximisation of economic surplus*** *taking into account various bid types and congestion in transmission corridor, which shall be updated with every new version of the price discovery algorithm…."*

The 'social welfare' is all encompassing, broader and public policy oriented which is the primary function of regulator of markets i.e. Central Commission. In future, if there are multiple objectives over and above the economics such as environmentally sensitive "emissions despatch" etc. it would be easier to incorporate the changes for social welfare maximization rather the restricting to maximization of economic surplus.

The imperative for the change is not clear in the Explanatory Memorandum. Hence, it is suggested thateither the rationale/imperative for the change may be explained in the Statement of Reasons or , the objective of 'social welfare maximization' in vogue since PMR, 2010 may be retained instead of maximization of economic surplus as proposed in PMR, 2020. Further, the value of social welfare caused should also be made public.

D. Objective of Power Exchange

In the draft PMR, 2020, Part – 4, Clause 8: Objectives of Power Exchange, it has been laid down as follows:

"..The Power Exchanges shall be established and operated with the following objectives:

(1) To design electricity contracts and facilitate transactions of such contracts;

(2) To facilitate extensive, quick and efficient price discovery and dissemination…"

In the extant PMR, 2010, the objective of the power exchange has been laid down as follows:

"…10. A Power Exchange shall function with the following objectives: -

(i) Ensure fair, neutral, efficient and robust price discovery

(ii) Provide extensive and quick price dissemination

(iii) Design standardised contracts and work towards increasing liquidity in such contracts

Explanation: Liquidity is a measure of ease of entering or exiting into a transaction (generally large transaction) with minimal impact in the market price of the transacted contract…."

The adjectives "fair", "neutral" and "robust" to price discovery as available in the PMR 2010 have been removed in the draft PMR 2020. The terms fair, neutral and robust are key cornerstones for price discovery and need to be retained.

Further, the terms "quick" and "extensive" have been used in the context of price dissemination in the PMR 2010. These terms have got mixed up in the draft PMR 2020 with price discovery.

In the draft PMR, 2020, the onus of discovery of uniform market clearing price for the Day Ahead Market or Real-time Market or any other market, as notified by the Commission, is proposed to be entrusted to the Market Coupling Operator (MCO) as and when this is implemented. However, till such time, the responsibility for fair, neutral, efficient and robust price discovery lies with the concerned Power Exchange(s). The facilitative process is required for the transition from existing price discovery platforms to MCO clearing platform as and when it is operationalized. Further, the prefix "extensive" for price discovery may not be suitable in the context as the Indian electricity market and may be removed.

Therefore, it is suggested that the extant objectives of the power exchange as laid down in PMR, 2010 which are based on sound economic principles may be retained in PMR, 2020 .

E. Demutualization in the Power Exchanges

In the draft PMR, 2020, Part 4, Clause 9: Eligibility criteria, one of the criteria for applicants to setup power exchange is as follows:

(2) The applicant is demutualized; for the purposes of this sub-regulation, the term "demutualized" means that the ownership and management of the applicant is segregated from the trading rights, in terms of these regulations.

Global exchanges, in the last few decades, have evolved from being member-owned entities into sophisticated business houses (now publicly listed). They have steadily completed the four key stages of the evolution cycle – electronization, demutualization, listing and consolidation. UNCTAD Report on Overview of the world's commodity exchanges, 2007 concluded that exchanges in both the developed and the developing worlds have looked to demutualize in order to establish their credentials for good governance, neutrality, fairness, provide a framework for self-regulation and secure the confidence of investors and traders alike.[2]

National Stock Exchange (NSE) is the first de-mutualised stock exchange in India. From day one, NSE has adopted the form of a demutualised exchange – the ownership, management and trading is in the hands of three different sets of people. NSE is owned by a set of leading financial institutions, banks, insurance companies and other financial intermediaries and is managed by professionals, who do not directly or indirectly trade on the exchange. This has eliminated any conflict of interest and helped NSE in aggressively pursuing policies and practices within a public interest framework[3].

Therefore, it is suggested that in case of Power Exchange(s) too, the ownership, management and participation (trading) should be segregated or 'truly' demutualized from each other rather only trading as proposed in the draft regulations. The suggested amendment in the clause is as follows:

(2) The applicant is demutualized; for the purposes of this sub-regulation, the term "demutualized" means that the ***ownership, management and participation*** *of the applicant is segregated* ~~***from the trading rights***~~*, in terms of these regulations.*

F. Introduction of New Bid Types/Modification of Existing Bid Type

In the draft PMR, 2020, Part 4, Clause 25: Approval or Suspension of Contracts by the Commission, it is proposed as follows:

"…(1) The Commission may, on its own or on an application made in this behalf, permit any Power Exchange to introduce new contracts as specified in clause (1) of Regulation 4 of these regulations:

…Provided further that the Power Exchanges may introduce new bid types or modify existing bid types conforming to the types and features of the contracts specified under Regulations 4, 5 and 6 of these regulations, after consultation with stakeholders and National Load Despatch Centre, under intimation to the Commission…."

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[2] https://unctad.org/en/Docs/ditccom20084_en.pdf

[3] http://www.idfc.com/pdf/white_papers/indian_exchanges.pdf

The intention of providing flexibility in the introduction of new bid types by Power Exchanges is apparently to promote innovation and creativity in product design customized to Indian system requirements. However, the introduction of new bid types and modification of existing bid types would have profound impact on the price discovery process impacting all market participants.

As an example, the maximum quantity per block bid was raised from 10 MW to 50 MW in 2008 to 100 MW in 2017 by IEX. In the grid code, it has been stipulated that step change in generation/demand quantum of the order of 100 MW or more has an impact on scheduling and ramping requirements. CERC directed examination of the impact of Block bids vide communication 6Sep 2017 with terms of reference of the study on the impact on scheduling, transmission corridor allocation, MCP, MCV, and smaller participants. The report was submitted by POSOCO in May 2018 **(Attached as Annexure – I)**. The extracts from the report are quoted as below:

"…The subject of block bids and associated market design issues are complex and more study/analysis needs to be done. ***Design parameters such as liquidity, concentration in the market, etc. may be considered before undertaking any change in the block bid specifications****.*

It was also agreed that ***any change in Power Exchange Market design which has a material impact on the price discovery, volumes cleared and social welfare will need to be approved by the Hon'ble Commission***

Ramping requirements in system operation need to be taken care of and any step changes should be avoided *as envisaged in the Grid Code. In future, detailed discussion on ramping restrictions on all segments of market could be taken up separately as need arises…."*

The design considerations for block bids were size of block bid, duration of block bid, impact of quantum and size of block bids on Market Clearing Volume, Market Clearing Price & Area Clearing Price, technical minimum considerations, Scheduling, Ramping, Real time grid operations, social welfare, paradoxical rejection of block bids and impact on smaller participants. Therefore, maximum size of block bids has a bearing on the price discovered and paradoxical rejection of large size block bid can impact the price discovery.

Further, the Draft PMR 2020 has proposed the implementation of Market Coupling Operator (MCO). Implementation of MCO envisages collection of bids through different Power Exchanges and an essential pre-requisite for this is the harmonization of bid-structures in all Power Exchanges participating in the process. As a consequence, all Power Exchanges must implement similar bid structures.

Hence, since the bid structures have a bearing on the price discovery and in order to facilitate harmonization for implementation of MCO, it is suggested that bids introduced in the Power Exchanges may be approved by the Hon'ble Commission after due stakeholder consultation.

G. Price Discovery Algorithm and Optimization

In the draft PMR, 2020, in the regulation 28. Information Technology Infrastructure and Trading System of Power Exchange, it has been provided that

"….(4) The algorithm of the software application for price discovery and market splitting shall be in compliance with the requirement specified in Regulation 5 as applicable and methodology mentioned in the bye-laws, rules and business rules of Power Exchange. The Power Exchange shall get the algorithm audited before commencement of operations and thereafter, once in every two years and submit the findings of the audit to the Commission. The resources employed shall have competence in audit of algorithms and relevant industry certifications such as CISA (Certified Information Systems Auditor) from ISACA or shall have empanelment with the Standardization Testing and Quality Certification Directorate under the Ministry of Electronics & Information Technology…."

In the regulation 31. Information Dissemination by Power Exchange, it has been provided that
(8) Power Exchange shall create and maintain a document on its website providing detailed description of the algorithm used for price discovery for all type of contracts. The description shall include bid types, details of how the algorithm results in maximisation of economic surplus taking into account various bid types and congestion in transmission corridor, which shall be updated with every new version of the price discovery algorithm:

In the regulation 39. Functions of the Market Coupling Operator, it has been provided that:
"…(2) The algorithm for enabling Market Coupling shall be developed and managed by the Market Coupling Operator and implemented with the approval of the Commission.
(3) Market Coupling Operator shall create and maintain a document on its website providing detailed description of the algorithm used for price discovery. The description shall include bid types, details of how the algorithm results in maximisation of economic surplus taking into account various bid types and congestion in transmission corridor, which shall be updated with every new version of the price discovery algorithm.
(4) The Market Coupling Operator shall use the algorithm to match the collected bids from all the Power Exchanges, after taking into account all bid types, to discover the uniform market clearing price, subject to market splitting.

It is welcom that draft PMR, 2020 provides for periodic auditing of the algorithm.
In the recent past, Security Constrained Economic Despatch (SCED) has been implemented in the country since April 2019 where in addition to considering the security constraints in the optimization, technical constraints such as ramping constraints are also factored. Further, RE penetration is increasing and ramping is going to be a key factor which shall be impacting the secure and reliable operation of the grid.

In the present market clearing algorithm implemented in the Power Exchanges, ramping has not been factored as a constraint while clearing the market and discovering the market clearing prices. The fundamental construct of the algorithm to include technical constraints from the generator/supply side is essential while causing economy and efficiency in the market. The algorithm may need to be formulated as an optimization function in order to achieve these objectives.

The relevant extracts from the Report on Block Bids are as follows:

"The problem of determining the MCP by matching the bidders to maximize social welfare is complex in many respects, particularly the inclusion of block bids with a 'All or None' characteristics make the problem a combinatorial one. ***This can be suitably addressed if the algorithm is modelled as an optimization problem with its objective function as social welfare maximization.*** *This would give flexibility to the algorithm which can be changed by adding or relaxing few constraints."*

Once the algorithm is reviewed and changed, the bids structures would also need to undergo a change so that the required technical information such as ramp rate is factored in the bids.

Further, the present market clearing engine in the Power Exchanges discovers market clearing volumes and prices on 15-minute basis i.e. on single period optimization basis. In near future, the aspects related to optimal scheduling and pricing across multiple time intervals for resources with intertemporal constraints, resource level constraints and system-wide constraints would assume significant importance. Therefore, initiatives have to be taken to evolve a multi-period optimization model with a look-ahead time horizon in a dynamic environment.

H. Information Dissemination

In the draft PMR, 2020 Regulation 31. Information Dissemination by Power Exchange, it has been provided that

"…(1) The Power Exchange shall display on its website links to all the relevant websites.
(2) Prices, volumes and historic prices of power traded shall be made available on the website of the Power Exchange and should be in downloadable format.
(3) Maximum, minimum and average of the traded prices for the month and average volume cleared for all type of contracts transacted on the Power Exchange shall be published on its website.
(4) The Power Exchange shall publish on its website, data tables with aggregate demand and supply curves for each type of contract…"

Presently, the information made available by the Power Exchanges in terms of Prices (Area wise & total) & Volumes (Area wise & total), Aggregate Sell bids & Aggregate Buy bids and Aggregate supply demand curves (only total).

In the interest of transparency, there is a need for more information dissemination in the public domain such as Area wise aggregated supply-demand curves, Total Consumer Surplus, Total Producer Surplus, Total Social Welfare, Percentage portfolios using block bids, Bid – Ask Spread, Time block wise / day-wise market concentration indices e.g., HHI (indicates level of competition) etc. The requirements have also been recommended in the Report on Block Bids submitted in May 2018. The information dissemination is vital for strengthening of Market Monitoring aspects.

General comments

I. Regulatory Oversight

In the order on Petition No. 155/2006 (Suo motu) regarding Guidelines for the grant of permission for setting up and operation of Power Exchange dated 06th February, 2007[4], the following has been mentioned:

"20. The general approach of the Commission is to allow operational freedom to the PX within an overall framework. The regulation would be minimal and restricted to requirements essential for preventing derailment/accidents and collusion. Private entrepreneurship would be allowed to play its role. The Commission shall keep away from governance of PX, which would be required to add value and provide quality service to the customers."

After more than a decade, the Power Exchanges have come a long way to establish themselves as an institution and valuable stakeholder of Indian power sector value chain. In the draft PMR, 2020, it is felt that Central Commission is transitioning from light handed regulation to a tighter approach towards market platform development, contract types, ownership, governance, surveillance and payment security.

The Commission's approach towards stricter rules and frameworks as the trajectory of the volumes traded in the electricity market marks a paradigm shift in strengthening the regulatory oversight.

J. DEEP Portal and OTC Platform

4 http://cercind.gov.in/08022007/GuidelinesforGrantofPermissionForsettingupandoperationofPowerExchange.pdf

DEEP (Discovery of Efficient Electricity Price) is a e-Bidding and e-Reverse auction portal for procurement of short term power by DISCOMs. The portal is an initiative of the Ministry of Power with the objective to introduce uniformity and transparency in power procurement by the DISCOMs and at the same time promote competition in electricity sector. The portal is meant for the short term procurement of the power. Short term procurement could be for a period of more than one day up to one year. The Guidelines for short term procurement of power was also notified on 30.03.2016 by Ministry of Power, Government of India, making it mandatory for all the Procurer(s) to procure short term power by using this e-Bidding portal from 04th April, 2016. Power Procurement from Power Exchange has been excluded from the scope of these guidelines.[5]

From the draft PMR 2020, it is not clear whether the DISCOMs participating in the DEEP Portal can also participate through the other OTC platforms as defined in the Regulations or not and accordingly needs to be clarified.

K. Clearing and Settlement

As the clearing and settlement function of Power Exchanges would also become increasingly more complex with increase in physical and financial products portfolio, the institutional mechanism as laid in accordance with Payment and Settlement Systems Act, 2007 and RBI oversight would ensure trust, reliability and accountability amongst the market players. Thus, this is a welcome step. More clarity on the governance aspects including incumbent's accountability may be provided in the draft PMR, 2020. In the future, such clearing facilities can also be utilized for settlement of POC charges, Payment Security Mehanisms, etc.

L. Market Coupling Operator (MCO)

In India, there is a single delivery physical market with multiple power exchanges. With the introduction of MCO, there would be reduction in multiplicity of prices. The optimal utilization of inter-regional transmission corridors would also be facilitated by MCO.

The proposed market coupling is distinct from coupling arrangement in Europe wherein Price Coupling of Regions – PCR exists which is a common price coupling algorithm used in the Single Day-Ahead Coupling to calculate power prices across Europe, while implicitly allocating auction-based cross-border capacity. Therefore, the proposal in draft regulations is not market coupling in strictest sense but merger of bids received through various power exchange platforms.

In Europe, before implementation of the coupling arrangements, EU Regulation 2015/1222 was published which established a guideline on Capacity Allocation and Congestion Management (CACM) ***(Annexure – II)*** and also served as a key piece of

[5] https://www.mstcecommerce.com/auctionhome/RenderFileGeneralAuctions.jsp?file=PPA-Revised-Guidelines-Short-Term.pdf

legislation for the single market in electricity. It sets out minimum harmonised rules for the ultimate single day-ahead and intra-day market coupling among various Nominated Electricity Market Operators (NEMOs) (power exchanges in Europe in various countries). As per the CACM regulation the NEMOs were directed to give a plan that sets out how NEMOs will jointly set up and perform the Market Coupling Operator (MCO) Functions (the "MCO Plan") (***Annexure – III).***

In Europe, development of a single price coupling algorithm, commonly known as EUPHEMIA (acronym for Pan-European Hybrid Electricity Market Integration Algorithm) took place. Since February 2014, Euphemia is progressively used to calculate energy allocation and electricity prices across Europe, maximizing the overall welfare and increasing the transparency of the computation of prices and flows.

In the Indian context, Market Coupling Operator (MCO) would play a significant role in merging of bids and clearing of market transactions. It would, in essence, translate into a single platform, single physical delivery market. It would be a transformational change and the transition needs to be handled. There is a need for extensive work on features of market coupling and roadmap for implementation.

An Expert Group on Transmission Corridor Allocation between Power Exchanges was constituted vide CERC Order dated 30th April 2015 in Petition No. 158/MP/2013 comprising of CERC Staff, POSOCO, CEA, IEX, PXIL, Independent Market Experts and Academia. The extracts from CERC Order dated 4th April 2016 on the Report submitted by Expert Group ***(Attached as Annexure – IV)*** are as follows:

"The recommendations of the Expert Group Are as follows:

…7.1 The solution obtained by ***merging the bids/market coupling of the two power exchanges would give the optimum solution with social welfare maximization****, in this segment, irrespective of congestion. This would* ***require changes*** *in the market design and amendment in the CERC Power Market Regulations in addition to resolution of the various other practical considerations such as confidentiality, running of merging solutions, logistics, settlement among multiple exchanges etc.…*

…7.6 The Export Group would like to place on record a word of caution regarding allocation of transmission corridor in case of congestion. The core underlying issue is pertaining to ***"competition for the market"*** *and* ***"competition in the market".*** *From a Regulatory perspective, equity and fairness needs to ensure competition in the market as the current methodology is inclined towards competition for the market.…*

…7.7 The optimal solution for allocation of transmission corridor to power exchanges in case of congestion could be obtained by merging of bids/market coupling method. A ***separate committee for long term solution*** *may look into the market design issues in a holistic manner including the transmission access methodology besides requirement of infrastructure, logistics, settlements etc. for implementation of merging of bids for optimal solution of transmission corridor allocation amongst multiple exchanges…"*

As market coupling is a complex concept, there is a need for detailed study on various aspects such as formulation of Market Clearing Engine, Algorithm, Objective Function, Intertemporal constraints, resource level constraints and system-wide constraints. Validation and testing of the engine and algorithm, Information Technology, Hardware and Data Interfacing, Operational Flexibility Provisions and host of other requirements.

In this regard, it is suggested that after finalization of the regulations, an expert group comprising of Staff of the Commission, System Operator, Power Exchanges and other independent electricity market experts may be formed to deliberate various alternatives and recommend the way forward and roadmap for the market coupling in Indian electricity market.

M. Limits on Bid Pricing

As per the extant PMR, 2010, Power Exchanges have the flexibility to decide the minimum and maximum bid prices in Day-Ahead segment. The present limits are maximum of ₹ 20/kWh and minimum of ₹ 0/kWh. The prime reasons for the limits are related to clearing software considerations with extrapolation of prices carried out in absence of real bids.

Internationally, it has been observed that maximum and minimum prices are stipulated by Regulator. In this respect, extracts from the European Commission Regulation (EU) 2015/1222[6] establishing a guideline on capacity allocation and congestion management are reproduced below:

"…1. The Harmonised Maximum Clearing Price limit proposal has to fulfil the ***objective of "promoting effective competition in the generation, trading and supply of electricity"*** *as the limits, for day ahead have to be* ***set at a level that does not restrict effective competition in the generation, consumption, trading or supply in the organized wholesale market.***
2. The Harmonised Maximum Clearing Price limit shall ***take into account the value of lost load*** *– assumed to be the price at which TSOs take curtailment action - and as a principle be maintained at a level that shall not limit the market at times of scarcity or oversupply*
3. The harmonised maximum clearing price for SDAC(Single Day Ahead Coupling) ***shall be increased by 1,000 EUR/MWh in the event that the clearing price exceeds a value of 60 percent of the harmonised maximum clearing price for SDAC in at least one market time unit in a day*** *in an individual bidding zone or in multiple bidding zones*
4. The increased harmonised maximum clearing price, set according to clause 3 ***shall apply in all bidding zon****es which participate in SDAC from five weeks after the day in which the event referred to therein has taken place;*
5. The NEMOs ***shall at least every two years reassess the Harmonised Minimum and Maximum Clearing Price Limits****, and share that assessment with all market participants and*

[6] http://www.nemo-committee.eu/assets/files/20170214_Harmonised%20Max-Min%20Prices%20Limit%20Proposal_Single%20Day%20Ahead%20Coupling.pdf

review it in relevant stakeholder forums organised in accordance with CACM Regulation. A reassessment shall also follow any application of the amendment rule…"

In almost all the markets RES/DG despatching has drastically changed the market outcomes in the recent years. The market prices can become negative e.g. Germany and Denmark with high penetration of RES/DG. New rules have been recently applied in Denmark considering possible market limitations to wind generation, if a negative market price occurs. The price limits for day-ahead (Fig. 1) and intra-day (Fig. 2) markets in Europe are given as follows[7][8]:

Maximum and minimum prices

Article 3

Harmonised maximum and minimum clearing prices for SDAC

1. The harmonised maximum clearing price for SDAC shall be +3000 EUR/MWh.
2. The harmonised minimum clearing price for SDAC shall be -500 EUR/MWh.

Figure 1: Limits on Day-Ahead Market Prices

Maximum and minimum prices

Article 3

Harmonised maximum and minimum clearing prices for SIDC

1. The harmonised maximum clearing price for SIDC shall be +9999 EUR/MWh.
2. The harmonised minimum clearing price for SIDC shall be -9999 EUR/MWh.

Figure 2: Limits on Intra-Day Market Prices

As the amount of zero marginal cost renewable generation on the system increases, the frequency and duration of negative spot pricing will increase. While many see this as a positive development and the benefits of flexible consumption in managing these generation surpluses, the lack of large-scale, long duration electricity storage means that short-term price volatility will grow.[9]

Therefore, in order to provide opportunities to storage (e.g. pumped storage, batteries etc.), there is a need to review the minimum market market clearing prices going below

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7 https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/ANNEXES%20NEMOs%20HMMCP%20FOR%20SINGLE%20INTRADAY%20COUPLING%20D/Annex%20I_ACER%20ID%20MAX-MIN.pdf

8 https://hupx.hu/uploads/Piacösszekapcsolás/NEMO/ACER%20DA%20MAX-MIN.pdf

9 http://watt-logic.com/2020/01/10/negative-electricity-prices/

zero. Further, as is the practice internationally, CERC may like to notify the maximum and minimum bid prices through appropriate regulatory provisions.

N. Whistle Blower policy

In the PMR, 2010, Clause 60 provides for Whistle Blowing policy as follows:

> *"..i. Market participants shall be entitled to report to the Commission either by letter or email, of any unscrupulous activity, wrongdoing or violation of law, as may come to their knowledge.*
>
> *ii. The provider of the above information shall be entitled to request that its identity be kept confidential and be not disclosed.*
>
> *iii. The Commission shall take strict action in case of any kind of retaliation to such an informant by any affected party …"*

It is suggested that the draft PMR, 2020 may also retain the whistle blower policy as per extant regulations in accordance with Whistle Blowers Protection Act, 2011.

O. Presentation made during the Public Hearing on 14th August 2020

A copy of the presentation made by POSOCO is also enclosed at Annex – V for ready reference.

Annexure - 1

पावर सिस्टम ऑपरेशन कॉर्पोरेशन लिमिटेड

(भारत सरकार का उद्यम)

POWER SYSTEM OPERATION CORPORATION LIMITED

(A Govt. of India Enterprise)

पंजीकृत एवं केन्द्रीय कार्यालय : प्रथम तल, बी–9, कुतुब इंस्टीट्यूशनल एरिया, कटवारिया सराय, नई दिल्ली–110016
Registered & Corporate Office : Ist Floor, B-9, Qutab Institutional Area, Katwaria Sarai, New Delhi -110016
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CIN: U40105DL2009GOI188682

पोसोको/ के.वि.वि.आ/

दिनांक : 24th May, 2018

सेवा में,
सचिव,
केन्द्रीय विद्युत् विनियामक आयोग,
तृतीय और चतुर्थ तल, चंद्रलोक बिल्डिंग
36, जनपथ
नई दिल्ली-110001

विषय: Report on review of Block bids at Power Exchange submitted in compliance to CERC letter dated 6th September, 2017

सँदर्भ: CERC letter No. PX/MISC/2017 dated 06.09.2017

महोदया ,

CERC vide communication dated 6th September 2017 directed POSOCO to examine the potential impact of 100 MW Block Bids inter-alia on the System operation and Market operation related issues in consultation with CERC and IEX. Several meetings were held on 14th June, 2017, 25th August, 2017, 27th September, 2017 and 30th November, 2017 to deliberate on the issues. Professor Soman and his team of researchers from IIT-Mumbai were also invited to deliberate various aspects associated with block bids on the 11th September 2018.

Accordingly, the report on the review of Block bids at Power Exchange prepared in consultation with CERC, IEX is attached for kind perusal of the Hon'ble Commission and further directions, if any. Delay in submission may kindly be condoned.

सादर धन्यवाद,

भवदीय,

एस एस बड़पंडा 24/5/18

(एस. एस. बडपंडा)

महाप्रबन्धक,रा.भा.प्रे.के.

Report on

Review of

Block Bids

At Power Exchanges

May 2018

Submitted in Compliance to CERC Letter dated 6th September 2017

Contents

1. Background

CERC Power Market Regulations, 2010 provides the Principles of Market and Market Design, encompassing Power Exchange functions. In the Day Ahead Market segment, the Power Exchanges offer different types of standardised contracts and the participants can bid using 'single-bids' or 'block-bids' which are spread over multiple time blocks. While single bids provide granularity, block bids are used to fulfil specific technical or commercial requirements of the generator or the loads.

Block bids impact the prices discovered and volume cleared in the Power Exchange markets depending on the quantum and size of block bids participating in the day-ahead market. As provided under the Power Market Regulations, the block bid parameters viz. maximum numbers of block bids, maximum quantity per block bids etc. are notified by the Exchange from time to time as per provisions of Business rules of the Power Exchange duly approved by the Hon'ble Commission. The immediate cause of concern arose when the maximum size of the block bid was revised by IEX from 50 MW to 100 MW as it may potentially impact both Market & System operations.

Some of the issues associated with block bids flagged by POSOCO vide communications dated 27th January 2010, 28th April 2017, 19th May 2017 and 22nd August 2017 (copies enclosed at Annex – I for ready reference) are as follows:

- Size of block bid
- Duration of block bid
- Impact of quantum and size of block bids on Market Clearing Volume, Market Clearing Price & Area Clearing Price
- Impact of maximum/minimum duration on technical minimum considerations
- Impact of maximum size on scheduling, ramping & real time grid operations
- Social welfare
- Paradoxical rejection of block bids
- Inclusion/exclusion of block bids create a more complex optimization problem impacting the overall social Welfare maximization
- Possibilities of squeezing out smaller players in the market

The above issues were deliberated in meetings held at CERC , NLDC and IEX. CERC vide communication dated 6th September 2017 directed POSOCO to examine the potential impact of 100 MW Block Bids inter-alia on the following System operation and Market operation related issues:

- Impact on ramping and scheduling of power
- Impact on transmission corridor allocation
- Impact on Market & Area Clearing Price and Market Clearing Volume
- Impact on smaller bidders

2. Salient Features of Power Exchange Implementation in India

The salient features of Power Exchange implementation in India are as follows:

(a) Voluntary participation

(b) A neutral platform

(c) Anonymous participation

(d) Competitive bidding

(e) Double sided auction

(f) 15 minute bidding

(g) Social Welfare Maximization

The advantages of Power Exchange implementation in India are likewise:

(a) Uniform Pricing

(b) Price discovery

(c) Congestion Management- Market Splitting

(d) Implicit auction

(e) Standardized contracts

(f) Risk management

(g) Investment Signals

(h) Competition amongst Power Exchanges

(i) Regulatory oversight

(j) Transparency and information dissemination

(k) Harnessing of Latent and Captive Generation

(l) Access opportunities for bulk and industrial consumers

3. Different Types of Block Bids and their Salient Features

Single bids will specify multiple sequences of price and quantity pairs for each time block in a portfolio manner. The quantity is assumed to vary linearly between two price pairs. Block Bid if selected will deliver/consume constant volume continuously for specified blocks. Block bid orders are All or None type wherein they are either accepted or rejected in toto. The following types of block bid orders are possible (not all are available in the Indian Power Exchanges):

- **Block bid**: Block bid will specify one price and one quantity for a combination of continuous 15-minutetime blocks. Selection criterion for inclusion/exclusion of the block bid is the average of Area Clearing Price (ACP) for the quoted 15-minute time blocks, of the respective Client's bid area vis-à-vis the quoted price for the block bid. It is a "All or None" type order.

- **Linked Block bids**:
    - All specifications as required by block bid, and,
    - Block bid only on acceptance of which, other bids linked to it can be considered for inculsion.
- **Flexible Hourly Bid**
    - Fixed volume that can be delivered/consumed, and,
    - Limit price

  Bid is considered for schedule in a time slot, which has maximum (for sellers) /minimum (for buyers) MCP. The bid might be rejected if MCP over the day does not meet requirement of limit price. It is a form of All or none type of bid wherein the time flexibility is there but volume is inflexible.

4. Selection criteria for Block Bids

The Block bid selection criterion is that the price quoted by the bidder should be better than the average of Area Clearing Price (ACP) for the quoted 15-minute time blocks, of the respective Client's bid area and it is an "All or None" type of order. The Bid selection based on time priority, in case of similarly placed bids, is considered only for Block bids. The Block bid selection in order of priority is Price followed by Volume and lastly time.

5. Paradoxical rejection of bid

In some cases, a block bid might be rejected by the system even though it would appear to be a valid bid. This can happen in a situation where inclusion of such bid might result in change in MCP at which this bid cannot be accepted. Rejection of such bids is known as paradoxically rejected bids. When block bid exclusion process is finished, it may have resulted in one or more block bids which appear to be rejected even though the bid price is more favorable than the average price. This type of rejection of a Block Bid is "Paradoxically rejected bids". The reason for rejection is that in case if the system accepts these bids, the average price of market changes in such a way that the block bids are no longer justified to be in. This may be both due to price as well as volume balancing.

6. Size of Block Bid

The Power Exchanges in accordance with the Rules, Byelaws and Business Rules of the Exchange, duly approved by the CERC, notify the Maximum Bid Limit for each Block Bid.

Initially, the maximum Block Bid quantity was restricted to 10 MW vide IEX circular dated 23rd June 2008, with a conditionthat it can be revised by the exchange from time to time, for which prior communication would be given to the Members.

Subsequently, the Maximum Bid Limit for each Block Bid was revised from 10 MW to 50 MW with effect from the Trading Day December 7, 2008 (Delivery day December 8, 2008) vide IEX Circular No: IEX/MO/08/ 2008.

The maximum quantity per Block bid has been increased from existing 50 MW to 100 MW starting from 12th April, 2017, trading day vide IEX Circular No: IEX/MO/237/2017.

The size of block bid also needs to be seen in the light of increasing trading volumes in the Power Exchange platform. The daily average cleared volume has increased from less than

1% of All India Demand met during 2008-2009 to about 3% presently.

7. Literature review on Block Bids in Power Exchanges

‘‘Block orders” are all-or-nothing orders of a given amount of electric energy in multiple consecutive hours at constant output, allowing participants to provide an average price for the combination of hours. This way, suppliers can offer lower prices, as the start-up cost is spread throughout the hours in the bid. It is generally assumed that blocks are price-setting orders, meaning that their prices are significantly different from zero and close to real market prices.

The reason block bids are featured in a Power Exchange design is because they allow linkage of bids thereby facilitating continuous running of the generating units and avoiding start/stops. In the absence of contiguous blocks, a supplier that wishes to run continuously may have to offer a very low price for intermediate time blocks, to “commit” so as to keep running the unit. Further, the Block bid by a generating station takes into account start-up and shutdown cost, ramp up and ramp down cost and operational cost. Blocks bid allow participants to provide an average price for a combination of hours. On average generators can offer cheaper prices for delivery in multiple consecutive hours, as the cost gets uniformly spread over a number of consecutive hours.

Introduction of flexible structures in Block bids may provide the volume flexibility, time flexibility along-with Minimum income criteria for bid clearing. Flexible volume block bids allow the market participants to specify their flexibility range i.e. Minimum volume a participant wants to get cleared and the Maximum volume a participant is intending to trade.

Richard P. O’Neill et.al [1]in their working paper titled “Equilibrium Prices in Power Exchanges with Non-convex Bids” discussed that uniform, linear prices in power exchange markets, such as in the Amsterdam Power Exchange (APX) Day-Ahead market or the Nord Pool Elspot market, that allow nonconvex, “fill or kill” block bids by market participants may not result in an equilibrium in an economic sense, nor do they maximize surplus to market participants. They proposed a multi-part, discriminatory, pricing mechanism that achieves a market equilibrium

Leonardo Meeus et.al [2]in their paper titled "Block order restrictions in combinatorial electric energy auctions" discussed the rationale of Block order restrictions. Internationally, the Power Exchanges restrict the size (MWh/h), the type (span in terms of hours) or the number (per participant per day) of blocks that can be introduced. They suggested that there is no significant correlation between restrictions (either size, type or number) and computational complexity (measured in terms of calculation time), likelihood of PRB (paradoxically rejected blocks) or trade efficiency (total gains from trade). The study concluded that the unrestricted use of blocks in immature or illiquid markets would increase price volatility, but as the markets have matured, those restrictions should be omitted or at least relaxed. Hence, liquidity of the market is a measure to gauge the restriction imposed on the size of the Block bid.

Dr Nicholas Ryan, Assistant Professor of Economics, Yale University suggest that plant offering blocks bids may make it easier to exercise market power in some circumstances. Because they "commit" plants to run, there is in effect less flexible competition for those plants that are offering single or flexible bids in a time block. These plants therefore have a greater effect on the time block price.

As per "Making Competition Work in Electricity" by Sally Hunt,

PREDICTING AND DETECTING MARKET POWER: How can we tell in advance whether there is likely to be market power in an electricity market? The first line of attack is to look at market concentration, generally using measures such as the Herfindahl Index, which is the sum of the squares of percentage market shares in a market.

The best solution to market power is to reduce the need for police and monitors by having enough competitors in the first place, by making entry easier, by divestiture, by relieving transmission constraints, and by allowing uneconomic plants to close, together with a price-responsive demand side.

The second best solution is contract cover (particularly during the transition to competitive markets). The third best solution (in fact the last resort) is to rely on forms of partial regulation such as price caps, bidding restrictions, and profit controls. But monitoring will always be necessary.

LIQUID MARKETS

We say the marketplaces are liquid if there are many buyers and sellers who can access each other easily and have access to information about the market prices. In liquid markets, the price settles down quite fast to a market price.

A defining feature of a liquid market is that it can generally absorb the addition or loss of a buyer or seller without a noticeable change in the market price. If there is good information, and the ability to resell, a competitive market comes to a single price for a specific product at a specific time and place.1

Mar Reguant [3] in the paper titled “Complementary Bidding Mechanisms and Start-up Costs in Electricity Markets” in Review of Economic Studies (2014) suggested that Costs of start - up / load adjustment are real and significantly affect generator bidding behaviour.

Paul R. Gribik et.al, [4] in their paper titled “Market-Clearing Electricity Prices and Energy Uplift” dated December 31, 2007, suggested that the general problem block bids try to solve is how to pay generators for “uplift” or start-up costs. Pricing models can differ in how they compensate generators for these costs. The practical consequence, of which system of payments will be best, will depend on the scenario and cannot be stated in general.

Sanchez Maria [5], 2010, in her Master’s Thesis, suggested the adoption of **Flexible Hourly Bid (FHB) by Hydro plants.** This concept, firstly introduced in Nord Pool, consists of a price/volume pair that could be activated in a single hour, which is unknown to the bidder. If any market hourly price along the day exceeds the price in the flexible hourly bid, then the bid is accepted and the execution is scheduled for the hour with the highest system price, so that it provides the highest overall social welfare for the market. It gives producers the best price, and is especially suited to hydro generators that have the ability to commit at any given time in substitution to expensive thermal generation.

Professor Shreevardhan A. Soman, Dr. Rajeev and Dr.Somsekhar, Electrical Engineering Department, Indian Institute of Technology Mumbai delivered a session on Advanced Bid Structures at the Power Exchange platform. They suggested that flexible structures in Block bid might be adopted by means of allowing Volume flexibility, Time flexibility and Minimum income criteria for bid clearing. Mixed Integer Linear Programming (MILP) techniques such as constant volume (Volume scheduling constraint with minimum and maximum limits, Minimum cost recovering constraint),variable volume schedule, stepped marginal cost, variable volume operation with ramping cost and multiple start-up and shutdown were discussed as alternative to the existing Block bids.

8. Meetings and deliberations

POSOCO had communicated to CERC, the likely issues that emerge out of increasing the Block Bid size vide several communication dated 27th January, 2010, 28th April, 2017, 19th May, 2017 and 22nd August 2017(**Copy enclosed at Annexure-1**) **.**Subsequently, A meeting was held at CERC on 14th June 2017, wherein Indian Energy Exchange gave a presentation on the highlighted issues. The presentation highlighted that the block bids with quantity greater than 50 MW (period considered – 13th April, 2017 to 31st May 2017) accounted for 11-26 percent out of the total block bid traded quantity, which is a sizeable number. Subsequently, another meeting was held on 25th August, 2017 regarding the subject matter. Finally, CERC vide its letter dated 6th September 2017(**Copy enclosed at Annexure-2**) , directed that POSOCO along-with CERC and IEX are required to examine the potential impact of 100 MW Block Bids on the System and Market Operation related aspects.

Several meetings were held on 14th June, 2017, 25th August, 2017, 11th September, 2017, 27th September, 2017 and 30th November, 2017 to deliberate on the issues. The summary of the deliberations held during the meetings are as detailed below:

- **Meeting on 14th June, 2017:**

  A meeting was held on 14th June 2017 at CERC to discuss on the Block bid aspects flagged by POSOCO vide letter dated 27th January, 2010 and28th April, 2017. IEX gave a presentation on the impact of 100 MW Block bid on schedule and ramping. They mentioned that they introduced 100 MW Block Bid size as a few generator clients wish to place Block bid size greater than 50 MW. Post introduction of 100 MW Block bid at the IEX from 12th April, 2017 (Period: 13th April, 2017-31st May, 2017), IEX observed the following:

- Block Bids with quantity greater than 50 MW to the total number of Block Bids: around 1 percent
- Number of Portfolios with Block Bids quantity greater than 50 MW to the total number of Portfolios with Block Bids: 0.81 percent
- Block Bids Trade quantity with bid greater than 50 MW to the trade quantity of the total number of Block Bids: 11 percent on an average, 26 percent as maximum
- Time Block-wise analysis of Single bid and Block bid depicting that Block Bid has smooth curve as compared to Single Bid curve
- Ramping analysis of IEX trade at State level(Period: 8th April, 2017-17th April, 2017)
- States DAM schedule compared with ISGS, LTA+MTOA and Bilateral transaction

Few other issues were deliberated like difference between MCP and ACP when there is no market splitting, final Area Clearing Volume greater than Market Clearing volume in no. of days. The copy of the presentation is attached at **Annexure-3**.

- **Meeting on 25thAugust 2017 at CERC**:

  IEX deliberated that in order to evaluate the impact of performance of Block Bid with size greater than 50 MW, they analysed data for 49 days (13th April, 2017- 30th June, 2017) and communicated their observations to the CERC vide letter dated 24th July, 2017(copy enclosed at **Annexure-4**). The salient points of their observations during the meeting are as follows:

  - **International Benchmark :** Block bid size in other International markets are as follows

Electricity Market	Countries	Max. Block Bid Size(MW)	Annual Trade (TWhr)
EPEXDE/AT	Germany/Austria	600	229 (Jun'16-Jul'17)
EPEXFR	France	600	105 (Jun'16-Jul'17)

Nord Pool	Nordic & Baltic Countries	500	390 (Jan'16-Dec'16)
N2EXUK	United Kingdom	500	108 (Jan'16-Dec'16)
EPEXNL	Netherlands	400	32 (Jun'16-Jul'17)
EPEXBL	Belgium	400	20 (Jun'16-Jul'17)
EPEXCH	Switzerland	150	23 (Jun'16-Jul'17)
IEX	India	100	42 (Jun'16-Jul'17)

Table 1: Block bid size Internationally

It is also important to mention here that in the European markets mentioned above, the Power Exchange volumes comprise of 50% and more of the total demand being served. In India, the Power Exchange volumes comprise of about 3% of all India demand met and thus, in percentage terms, itis considerably smaller as compared to European markets however in volume terms it is comparable with some European countries.

- **Price difference between Market Clearing Price(MCP) and Area Clearing Price (ACP) in no Congestion blocks**: Due to Congestion in some of the blocks during the day, there might be a possibility in change in the prices of non-congested blocks as well. It was mentioned that due to congestion in certain blocks of the day, the demand and supply situation changes not only in congested time blocks but also in non-congested time blocks, due to inclusion/rejection of earlier rejected/included marginal bids. This may result in price difference between MCP and ACP. The phenomenon was illustrated with an example showing that on several days the Block Bid with quantity >50 MW has not changed its status (i.e. Block Bid selected in Provisional remained selected in Final and/or Block Bid rejected in Provisional remained rejected in Final) in Provisional and Final results but still difference in MCP and ACPs has been noted in uncongested blocks. Internationally, it was pointed out that the sample price of Nord-Pool for a typical day wherein all price areas (ACPs) are same indicating no congestion for the above mentioned time blocks, however system price i.e. MCP ("SYS" price) is different from ACPs.

- **Final Cleared Volume greater than Market clearing volume on number of days**: IEX mentioned that due to congestion, the changes in prices in upstream and downstream of congestion might result in final ACV greater than the MCV. This may happen due to selection of Buy (single/Block) bid in the Upstream, which was rejected in unconstrained result, and selection of Sell (single/Block) bid in the downstream, which was rejected in unconstrained results. They had observed that on several days the Block bid with quantity greater than 50 MW has not changed its status in provisional and final results but still there are situation where ACV>MCV occurred.

- **Contribution of ramping in DAM schedule of Collective transactions** is insignificant as compared to other contract types.
  However, POSOCO clarified that ramping of conventional generation stations is going to be a major technical consideration to address the intermittent generation of renewable energy. Hence, ramping needs to be considered , which can be deliberated separately in details. It is also pertinent to mention that unlike other Power Exchanges worldwide, the volumes in the Indian Power Exchange(s) are lower in terms of the percentage of total demand met i.e., in India PX volumes are of the order of 3% only. Further, it is also then evident that the participants, including generators, in the Power Exchange(s) are having a portfolio comprising of different types of transactions. Thus, it is less likely that unit commitment decisions are solely based on the Power Exchange trades.

- **Meeting on 27th September, 2017 at NLDC**
  Discussions were held on various Market Design aspects related to Block Bids, some of them are enumerated below:
  - Optimal size of block bids and its impact on prices, volumes and social welfare with reference to the International best practises was discussed. In addition, it emerged that computation of Social Welfare is carried out in the Power Exchanges on a daily basis and may be posted regularly at their website.

- **Liquidity of Indian Electricity Market**: Liquidity is one of the decision criteria for the size of block bids. There were discussions on the various measures to measure liquidity of the electricity market.

    - **Herfindahl-Hirschman Index (HHI):**

      The Herfindahl index (also known as Herfindahl–Hirschman Index, HHI, or sometimes HHI-score) is a measure of the size of firms in relation to the industry and an indicator of the amount of competition among them. Named after economists Orris C. Herfindahl and Albert O. Hirschman, it is an economic concept widely used to measure concentration. It is defined as the sum of the squares of the market shares of the firms within the industry (sometimes limited to the 50 largest firms), where the market shares are expressed as fractions. The result is proportional to the average market share, weighted by market share. As such, it can range from 0 to 1.0, moving from a huge number of very small firms to a single monopolistic producer. Increases in the Herfindahl index generally indicate a decrease in competition and an increase of market power, whereas decreases indicate the opposite.

      CERC calculates the ratio for Market Monitoring purpose to arrive at the Market concentration of the Trading Licensees. The HHI of IEX Day-Ahead Market for Buyers and Sellers illustrated by IEX (As per CERC Market Surveillance Committee Report July'17 to Sep'17)

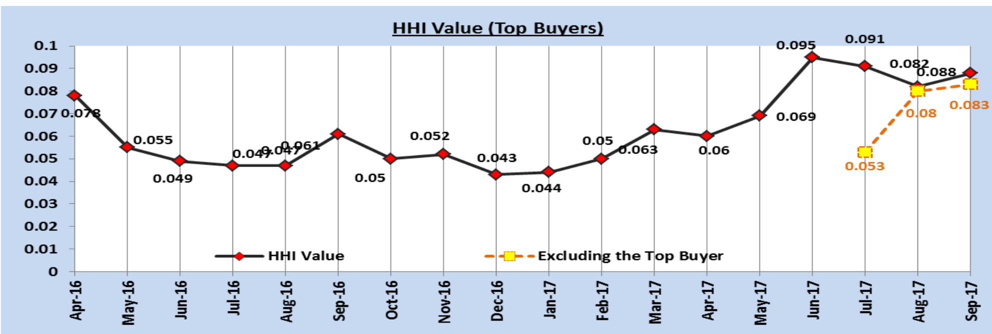


Figure 1: HHI Buyers

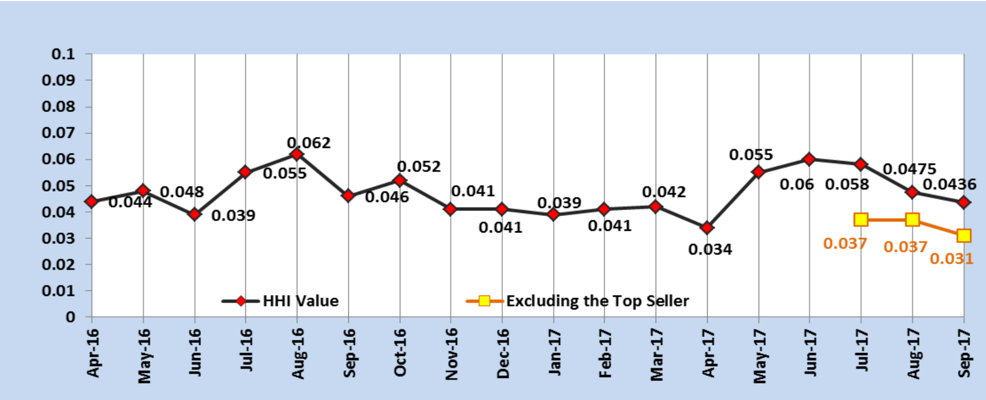


Figure 2: HHI Sellers

<u>The description of HHI Index is as below:-</u>

- *<u>A HHI index below 0.01 (or 100) indicates a highly competitive index.</u>*
- *<u>A HHI index below 0.15 (or 1,500) indicates an unconcentrated index.</u>*
- *<u>A HHI index between 0.15 to 0.25 (or 1,500 to 2,500) indicates moderate concentration.</u>*
- *<u>A HHI index above 0.25 (above 2,500) indicates high concentration.</u>*

- **Contribution of Top ten Buyers/ Sellers**

The percentage contribution of Top ten Buyers/Sellers in Day Ahead Market (Collective transactions) for the period 1st September, 2017- 29th March, 2018 is shown below. It is observed that the Top ten Sellers have an average contribution of 51 percent and the Top ten Buyers have an average contribution of 81 percent in the total trade during the above-mentioned period, indicating some degree of concentration in the Day Ahead Market(Collective transactions). This is also evident from the figure below.

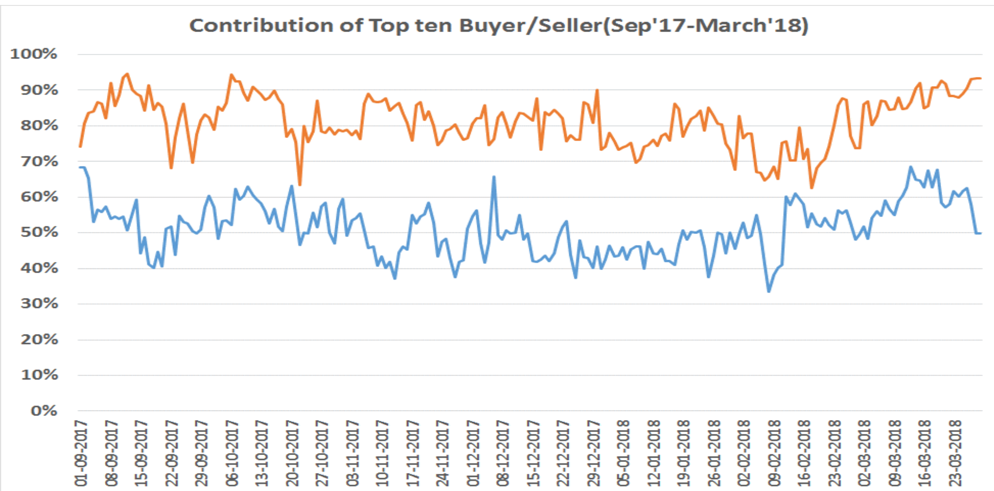


Figure 3: Contribution of Top ten Buyer/Seller

- In IEX, a maximum 60 Block Bids are allowed to each participant. Internationally, the limits on size and no. of block bids per participant are as below:

Electricity Market	Country	Max. Block Bid Size (MW)	Max. No. of Block Bids per participant
EPEX DE/AT	Germany/ Austria	600	100
EPEX FR	France	600	40
Nord Pool	Nordic & Baltic Countries	500	50
EPEX UK	United Kingdom	500	80
N2EX UK	United Kingdom	500	80
EPEX NL	Netherlands	400	40
EPEX BL	Belgium	400	40
EPEX CH	Switzerland	150	40
IEX	India	100	60

Table 2: Block bid per participant

- Block bids were primarily introduced to take care of the technical requirements of generators e.g., technical minimum generation, etc. The merit of allowing block bids for buyers was deliberated and it emerged that due to State Open Access Regulations (like in Rajasthan, Haryana, Punjab) the Open Access Industries need power on firm basis; hence it cannot be restricted to sellers only.
- Internationally, Power Exchanges are deciding the size of Block Bid on liquidity basis.The Block Bid size limit and liquidity in major Power Exchanges are as follows:

- **Impact on Real time System operation – Ramping, scheduling and corridor utilization**

NLDC mentioned that IEGC provisions stipulate that no generator/user shall cause a sudden variation (step change) of 100 MW and more. Presently, there are no such restrictions imposed in the Power Exchange. It was also mentioned by NLDC that trades cleared in the Power Exchange thus have an impact on scheduling and consequently, on real time operation. IEX clarified that collective transactions are only one of the components in the portfolio and a view needs to be taken in totality. It was felt, that there is a need of detailed discussion on this subject wherein schedules arising out of Exchange Transactions as well as other modes of transactions will have to be considered in totality. In future, if need arises, ramping requirements may be imposed in the Power Exchange bidding process.

NLDC also mentioned that exclusion of a marginal block bid on a congested corridor may lead to under-utilization of the corridor. This under-utilization will increase as the size of the block bid increases (50 MW or 100 MW) and is a matter of concern. IEX mentioned that presently, it has been observed that mostly the block – bids are not the marginal bids generally and also that there is hardly any under-utilization of the congested corridor. In past four years in only two time blocks (30 minutes) there was under utilisation of 0.01 MW each, that too due to rounding off as may be seen from the table below. A watch need to kept to see if there are any cases of under-utilisation after increase in block bid size.

Assessment Period 01-04-13 to 19-09-17		
Region/Area	**Blocks of Congestion**	**Max. under-utilization in a time block (MW)**
SR Import	102903	0.01 (2 Blocks)
NR Import	22638	Nil
N3 Import	11596	Nil
S2 Import	35794	Nil
W3 Export	6952	Nil

- **Meeting on 30th November 2017**

  The last meeting took place at the IEX Premises on 30th November, 2017. IEX presented the entire market clearing process including block bids. The following was agreed during the meeting:

  - The subject of block bids, their usage and impact on market in terms of prices and volumes is complex
  - It was agreed that a formal consultation would be carried out by the Power Exchange(s) in case any change in size of the block bid in future.

- It was also agreed that any change in Power Exchange Market design which has a material impact on the price discovery, volumes cleared and social welfare will need to be approved by the Hon'ble Commission.
- Impact on Smaller Market Participants -Concerns were raised by NLDC, regarding the usage of large size block bids and their impact on the market clearing, specially regarding possible exclusion of the smaller market participants. IEX e*xplained that, during each step of* Price Calculation, the system is unbiased to quantity and considers the price of individual portfolios for deriving the Clearing Price. Hence large block bid size may have no impact on smaller participants.
- The economic principle suggests that the market outcomes are most efficient when the price is discovered based on social welfare maximization principles. Regulation 11 A of Power Market Regulations has also mandated the exchange to carry out the price discovery based on the economic principle of social welfare maximization principles while creating surplus for both buyers & sellers. Accordingly, the exchange must ensure that while matching the buy/sell bids for price discovery the social welfare maximization should also be met. The problem of determining the MCP by matching the bidders to maximize social welfare is complex in many respects, particularly the inclusion of block bids with a 'All or None' characteristics make the problem a combinatorial one. This can be suitably addressed if the algorithm is modelled as an optimization problem with its objective function as social welfare maximization. This would give flexibility to the algorithm which can be changed by adding or relaxing few constraints.
- IEX is submitting the surveillance reports to the Hon'ble Commission on a quarterly basis in which it is providing the month-wise HHI index giving an measure of the level of competition in the exchange. Some additional parameters viz. time block-wise or day-wise HHIs, bid-ask spread etc. may be captured which would give a better understanding of the level of competition in the market. Further, the social welfare achieved along with a consumer and producer surplus may also be captured giving an indication of market efficiency.

9. Interaction with Academia (IIT Mumbai) on 11th September, 2017

CERC in the communication to POSOCO suggested that academician/professional having experience in Power Exchanges may be consulted for the study. In this connection, POSOCO invited **Professor Shreevardhan A. Soman**, Electrical Engineering Department, Indian Institute of Technology Mumbai for an interactive session on "Impact of Block bid on price discovery and volumes cleared at Power Exchanges" on 11th September 2017 at National Load Despatch Centre**.** He was accompanied by two of his Research Scholars viz. Dr. Rajeev and Dr.Somsekhar.

Block bid features

They presented the concept of Market clearing with Block bids in DAM. They mentioned that Block Bids are Fill or Kill type Bid order. Various types of Block bids were explained such as linked bid (Mother-Child bids), Flexible bids etc. The reason for Introduction of Block Bid is that they encourage participation of generators with high start-up and shutdown cost and guarantee operational volumes over consecutive hours, allowing them to bid at competitive price. However, the problem with Block bids is that there is a possibility of Paradoxical Rejection of Bids (PRB). They also suggested that segregation of cost components like start up, shutdown, running, ramping and marginal cost allows block bidders to be even more competitive and probability of PRB comes down.

Suggested New Features to address the issues related with Block bid

They suggested that in order to address the issues related with Block Bids, flexible Bid structures may be introduced. The flexible bids have the inherent advantages, as follows:

- Volume flexibility
- Time flexibility
- Minimum income criteria for bid clearing

The relevant papers shared by the eminent faculty from IIT Mumbai and the presentation enclosed at **Annexure-5.**

10.Recommendations

The recommendations are as follows:

(a) The subject of block bids and associated market design issues are complex and more study/analysis needs to be done. Design parameters such as liquidity, concentration in the market, etc. may be considered before undertaking any change in the block bid specifications.

(b) A formal consultation would be carried out by the Power Exchange(s) with NLDC and CERC in case of change in block bid size in future.

(c) It was also agreed that any change in Power Exchange Market design which has a material impact on the price discovery, volumes cleared and social welfare will need to be approved by the Hon'ble CommissionRamping requirements in system operation need to be taken care of and any step changes should be avoided as envisaged in the Grid Code. In future, detailed discussion on ramping restrictions on all segments of marketcould be taken up separately as need arises.

(d) The market design principles as laid down in the CERC Power Market Regulations provides for economic principle of social -welfare maximisation during price discovery. Minimum information dissemination requiements have been specified in the CERC Power Market Regulations However, there is no bar on additional information dissemination by the Power Exchanges. Hence it is recommended that the following information should be made available on the respective websites by the Power Exchanges:

   a. Producer surplus
   b. Consumer surplus
   c. Total social welfare
   d. Total number of portfolios traded
   e. Percentage contribution of block bids both in terms of number of block bids and market clearing volume (energy)Bid-Ask spread

(e) The economic principle suggests that the market outcomes are most efficient when the price is discovered based on social welfare maximization principles. Regulation 11 A of Power Market Regulations has also mandated the exchange to carry out the price discovery based on the economic principle of social welfare maximization principles while creating surplus for both buyers & sellers. Accordingly, the exchange must ensure that while matching the buy/sell bids for price discovery the social welfare maximization should also be met. The problem of determining the MCP by matching the bidders to maximize social welfare is complex in many respects, particularly the inclusion of block bids with a 'All or None' characteristics make the problem a combinatorial one. This can be suitably addressed if the algorithm is modelled as an optimization problem with its objective function as social welfare maximization. This would give flexibility to the algorithm which can be changed by adding or relaxing few constraints.

(f) IEX is submitting the surveillance reports to the Hon'ble Commission on a quarterly basis in which it is providing the month-wise HHI index giving an measure of the level of competition and liquidity in the exchange. Some additional parameters viz. time block-wise or day-wise HHIs, bid-ask spread etc. may be captured which would give a better understanding of the level of competition in the market. Further, the social welfare achieved along with a consumer and producer surplus may also be captured giving an indication of market efficiency.

(g) New types of bids, 'exotic bids' should be examined to cater to specific requirements of the different types of participants in market. For example, while placing bids, the Hydro generators may give energy on RTC/ defined time blocks, and allow for flexibility in the volume cleared in each time block depending on say, the price (high prices would indicate higher demand to be met & hydro optimization will help).

References of Literature Survey

S. No	Title of the Paper/Document/Article	Author/Group/Copyright Holder	Year of Publication
1	"Equilibrium Prices in Power Exchanges withNon-convex Bids" IEEE working paper	Richard P. O'Neill, Paul M. Sotkiewicz, and Michael H. Rothkopf	January 2006, revised July 2007
2	"Block order restrictions in combinatorial electric energy auctions" European Journal of Operational Research 196 (2009) 1202–1206	Leonardo Meeus, KarolienVerhaegen, Ronnie Belmans	2009
3	"Complementary Bidding Mechanisms and Start-up Costs in Electricity Markets"Review of Economic Studies (2014) 81, 1708–1742,	Mar Reguant	2014
4	"Market-Clearing Electricity Prices and Energy Uplift" dated December 31, 2007	Paul R. Gribik, William W. Hogan, and Susan L. Popei	2007
5	"Day-Ahead Electricity Market: Proposals to adapt complex conditions in OMEL"submitted in partial fulfilment of Master's thesis at Comillas Pontifical University, Spain	Sanchez Maria	2010

List of Annexures

Annexure No.	Detail of Annexure
1	NLDC Communications to CERC regarding Block Bids
2	CERC Letter dated 6th September 2017 regarding constitution of Committee to study impact of increase in maximum quantity of Block bids from 50 MW to 100 MW
3	IEX Presentation on Block bids at CERC on 14th June 2017
4	IEX Letter to CERC dated 24th July 2017 regarding increase in maximum quantity of Block bids from 50 MW to 100 MW
5	Presentations and literature on Block bids made by Professor Shreevardhan A. Soman, Dr. Rajeev and Dr.Somsekhar, Electrical Engineering Department, Indian Institute of Technology Mumbai

ANNEXURE 1

केन्द्रीय विद्युत विनियामक आयोग

CENTRAL ELECTRICITY REGULATORY COMMISSION

सत्यमेव जयते

के वि वि आयोग
CERC

Sanoj Kumar Jha, IAS
Secretary

Ref: PX/Misc/2017

Date : 06/09/2017

The CEO
Power System Operation Corporation Limited (POSOCO)
B-9 (1st Floor)
Qutab Institutional Area,
Katwaria Sarai,
New Delhi

Subject: Increase in maximum quantity of Block Bids from 50 MW to 100 MW at IEX

Sir,

This has reference to the meeting held at CERC on 25th August 2017 regarding increase of maximum quantity for Block Bids from 50 MW to 100 MW by IEX.

2. Based on the discussion held during the meeting, it was decided that POSOCO in co-ordination with IEX and CERC shall examine the potential impact of 100 MW Block Bids inter-alia on the following System and Market operations related issues:

- Impact on ramping and scheduling of power
- Impact on Transmission corridor utilization
- Impact on Market and Area Clearing Price & Volume
- Impact on Smaller Bidders

3. If required, POSOCO may also consult any other academician or professional having expertise in power sector/exchanges to assist them in undertaking the study. POSOCO may submit the findings to the Commission within a month's time for further directions on the above issue.

Yours faithfully

06/09/17

(Sanoj Kumar Jha)

Copy to:

To
The CEO
INDIAN ENERGY EXCHANGE LIMITED (IEX)
Unit No. 3,4,5 and 6, Plot No. 7
Fourth Floor, TDI Centre,
District Center, Jasola,
New Delhi – 110025

तीसरी मंजिल, चन्द्रलोक बिल्डिंग, 36, जनपथ, नई दिल्ली-110 001
Third Floor, Chanderlok Building, 36, Janpath, New Delhi-110 001
Phone : 91-11-2375 3915, Fax : 91-11-2375 3923, E-mail : secy@cercind.gov.in / secyskj@gmail.com

ANNEXURE-2

POWER GRID CORPORATION OF INDIA LIMITED
NATIONAL LOAD DESPATCH CENTRE

Dated: 27th January 2010

The Managing Director
Indian Energy Exchange Limited
100A/1 Ground Floor, Capital Court,
Olof Palme Marg, Munirka,
New Delhi-110067

Subject: Prices in IEX – Impact of Block Bids

Sir,

This has reference to the prices discovered on the IEX Platform for the delivery date 17th January 2010. On this day, congestion was present in the import towards Northern Region and the Market Split in the IEX into 'Northern Region' (deficit region) and 'Rest of India' (surplus region). From the prices published on the IEX Website, it is observed that during 0000 to 0600 Hrs, the prices in the surplus area are higher than the unconstrained market price. A similar phenomenon is observed again during the period 1700 Hrs to 2400 Hrs.

It is understood that such behavior is normally associated with inclusion/exclusion of block bids (if exclusion of trades on account of inadequate margins is not considered). In this context, the following issues need further deliberation for a better understanding:

(a) Specific provisions in the CERC Regulations (including Power Market Regulations) and the Business Rules / Bye Laws / Rules of IEX in respect of Block Bids, if any.
(b) Initially, as given to understand by IEX, the maximum block bid quantum was restricted to 10 MW. This was modified to 50 MW by IEX through a Circular dated 6th December 2008. The rationale which necessitated this modification need to be understood by all.
(c) Block Bids is mentioned in the Business Rules of IEX at Para 17.1(b) and 18.3(e). However, the tick size is also relevant.
(d) Maximum/minimum duration also needs to be deliberated for the Block Bids based on the technical minimum considerations.
(e) The kind of utilities (generators, consumers, captives, portfolio bidders) placing such kind of block bids and their bidding behavior.
(f) The proportion of block bids on a daily basis (pattern).

It is a well established fact that the inclusion/exclusion of block bids creates a more complex optimization problem thereby impacting the overall social welfare maximization. There can be peculiar price movements if a high proportion of block bids is present.

As the market is maturing, it is requested that the above issues may kindly be addressed and a discussion could be organized.

Thanking you,

Yours faithfully,

27/01/10

S. K.Soonee
Executive Director (SO & NLDC)

CC: 1. **Secretary, CERC**
2. **All RLDC Heads**

पावर सिस्टम ऑपरेशन कारपोरेशन लिमिटेड
(भारत सरकार का उद्यम)
POWER SYSTEM OPERATION CORPORATION LIMITED
(A Govt. of India Enterprise)

पंजीकृत एवं केन्द्रीय कार्यालय : प्रथम तल, बी-9, कुतुब इंस्टीट्यूशनल एरिया, कटवारिया सराय, नई दिल्ली-110016
Registered & Corporate Office : Ist Floor, B-9, Qutab Institutional Area, Katwaria Sarai, New Delhi -110016
CIN : U40105DL2009GOI188682, Website : www.posoco.in, E-mail : posococc@posoco.in, Tel.: 011- 41035696, Fax : 011- 26536901

संदर्भ संख्या: पोसोको/एनएलडीसी/आई॰ई॰एक्स॰/२०१७/ 105 दिनांक: 28th अप्रैल 2017

सेवा में,

निदेशक (मार्केट ऑपरेशन)
इंडियन एनेर्जी एक्स्चेंज (आई॰ ई॰ एक्स॰)
चतुर्थ तल, टी॰ डी॰ आई॰ सेन्टर, प्लॉट सं॰ – **7**, जसोला, नई दिल्ली-**110025**

विषय: Increase in Maximum Quantity per Block Bid from 50 MW to 100 MW.

संदर्भ: IEX circular no. IEX/MO/237/2017 dated 11th April 2017

महोदय,

This has reference to the circular no. IEX/MO/237/2017 dated 11th April 2017 vide which the maximum quantity per Block bid was increased from 50 MW to 100 MW w.e.f. 12th April 2017. In this context, it is pertinent to mention that sub-clause (j) of clause 5.2 of CERC (Indian Electricity Grid Code) Regulations, 2010 provides as under:

"Except under an emergency, or to prevent an imminent damage to a costly equipment, no User shall suddenly reduce his generating unit output by more than one hundred (100) MW (20 MW in case of NER) without prior intimation to and consent of the RLDC, particularly when frequency is falling or is below 49.5 Hz.. Similarly, no User / SEB shall cause a sudden variation in its load by more than one hundred (100 MW) without prior intimation to and consent of the RLDC."

A step change in generation and demand quantum of the order of 100 MW or more has an impact on scheduling and ramping requirements.

It has also been observed that during the last one month final cleared volume was more than the unconstrained market clearing volume on a number of days. It is understood that one of the possible reasons for such phenomenon is block bids.

It is suggested that we may hold a meeting at a mutually convenient date/time to discuss and better understand the associated issues.

सादर धन्यवाद,

भवदीय,
एस एस बड़पंडा
(एस.एस. बड़पंड़ा)
अपर महाप्रबंधक

प्रतिलिपि: सचिव, केंद्रीय विध्युत विनियामक आयोग
तीसरी मंजिल, चंद्रलोक बिल्डिंग, ३६ जनपथ, नई दिल्ली -११०००११

पावर सिस्टम ऑपरेशन कारपोरेशन लिमिटेड
(भारत सरकार का उद्यम)
POWER SYSTEM OPERATION CORPORATION LIMITED
(A Govt. of India Enterprise)

पंजीकृत एवं केन्द्रीय कार्यालय : प्रथम तल, बी–9, कुतुब इंस्टीट्यूशनल एरिया, कटवारिया सराय, नई दिल्ली–110016
Registered & Corporate Office : Ist Floor, B-9, Qutab Institutional Area, Katwaria Sarai, New Delhi -110016
CIN : U40105DL2009GOI188682, Website : www.posoco.in, E-mail : posococc@posoco.in, Tel.: 011- 41035696, Fax : 011- 26536901

संदर्भ संख्या: पोसोको/एनएलडीसी/आई॰ई॰एक्स॰/२०१७/ **दिनांक:** 19th May, 2017

सेवा में,

निदेशक (मार्केट ऑपरेशन)
इंडियन एनेर्जी एक्स्चेंज (आई॰ ई॰ एक्स॰)
चतुर्थ तल, टी॰ डी॰ आई॰ सेन्टर, प्लॉट सं॰ – **7,** जसोला, नई दिल्ली-**110025**

विषय: Difference between ACP and MCP during time blocks with no Market splitting

संदर्भ: Letter to IEX No: पोसोको/एनएलडीसी/आई॰ई॰एक्स॰/२०१७/105 dated 28th April, 2017

महोदय,

This has reference to the above-mentioned letter to IEX wherein the maximum quantity per Block bid was increased from 50 MW to 100 MW w.e.f. 12th April 2017.

In this context, it is pertinent to mention that for the past few months, it has been observed that there is a price differential between the Area Clearing price and Market Clearing price, even for the time blocks where market splitting has not occurred in Day Ahead Market Collective transaction. After 12th April, 2017, the phenomenon occurred more frequently. The details for the period 1st January 2017-19th May, 2017 are enclosed at Annexure-I.

Such type of phenomenon is counter-intuitive, because as per the market design principles of Power Market Regulations, it is expected that there will be no price differential between the Area Clearing price and Market Clearing price, for the periods when there is no market splitting. One of the possible reasons for such phenomenon could be large size of block bids.

The matter needs in depth analysis and further discussion.

सादर धन्यवाद,

भवदीय,
एस एस बड़पंडा 19/5/17
(एस.एस. बड़पंड़ा)
अपर महाप्रबंधक

प्रतिलिपि: सचिव, केंद्रीय विध्युत विनियामक आयोग
तीसरी मंजिल, चंद्रलोक बिल्डिंग, ३६ जनपथ, नई दिल्ली -११०००११

Annexure-I

Month	Count of Time blocks (Price difference b/w MCP and ACP when there is no market splitting)				
	Less than 10 paise	10-20 paise	20-30 paise	Difference greater than 30 paise	Total Time Blocks in Month
January, 2017	859	52	9	3	2976
February, 2017	531	33	13	4	2688
March, 2017	872	34	9	3	2976
1-12th April, 2017	322	20	1	0	1152
13th April-19th May, 2017	1391	61	12	8	3552

पंजीकृत एवं केन्द्रीय कार्यालय : प्रथम तल, बी-9, कुतुब इंस्टीट्यूशनल एरिया, कटवारिया सराय, नई दिल्ली-110016
Registered & Corporate Office : Ist Floor, B-9, Qutab Institutional Area, Katwaria Sarai, New Delhi -110016
CIN : U40105DL2009GOI188682, Website : www.posoco.in, E-mail : posococc@posoco.in, Tel.: 011- 41035696, Fax : 011- 26536901

संदर्भ संख्या: पोसोको/एनएलडीसी/के.वि.वि.आ/**2017/** **दिनांक**: 22nd August,2017

सेवा में,
सचिव
केंद्रीय विध्युत विनियामक आयोग
तीसरी मंजिल, चंद्रलोक बिल्डिंग,३६ जनपथ,नई दिल्ली -११०००११

विषय: Increase in maximum quantity of Block bid from 50 MW to 100 MW at Indian Energy Exchange

संदर्भ:
1. Discussion Meeting at CERC dated 14th June 2017
2. POSOCO Letter to IEX dated 28th April 2017
3. IEX circular no. IEX/MO/237/2017 dated 11th April 2017
4. NLDC Letter to IEX dated 27th January 2010

महोदय,

Indian Energy Exchange Ltd (IEX) recently increased the block bid size from 50 MW to 100 MW from trading date 12th April, 2017 vide circular No. 237 dated 11th April, 2017. National Load Despatch Centre (NLDC) had flagged some of the relevant issues related to Block bids in the earlier communications to CERC and IEX dated 27th January, 2010 and 28th April, 2017(Copy enclosed at Annexure –I & II).

Any change in the bidding structure by the Power Exchange(s), such as increasing the block bid size from 50 MW to 100 MW, requires consultation with NLDC, being the Nodal agency for Collective transactions as per CERC Regulations. In this case, the consultative approach was missing on part of IEX. NLDC observed the behavior and subsequently vide letter dated 28th April, 2017 pointed out the issues related to the subject matter to IEX. A meeting was also held at CERC on 14th June 2017, wherein Indian Energy Exchange gave a presentation on the highlighted issues. The presentation highlighted that the block bids with quantity greater than 50 MW (period considered - 13th April, 2017 to 31st May 2017) accounted for 11-26 percent out of the total block bid traded quantity, which is a sizeable number. It may be worthwhile to mention that any inclusion or exclusion of a block bid has an impact on the price discovery mechanism, volumes cleared and the consequential social welfare maximization. The important points which need to be considered in view of these facts are as follows:

- A step change in generation and demand quantum of the order of 100 MW or more has an impact on scheduling, ramping requirements and the real time grid operation
- Final cleared volume in Collective transactions is observed to be more than the Unconstrained market clearing volume on a number of days
- In case if there is no congestion in a time block, the selection/rejection of block bids leads to change in Market Clearing Price and Area Clearing Price(s)
- A particular set of market participants, bidding more than 100 MW and above, may squeeze out a substantial percentage of small quantum sized players.

Since the Electricity market is evolving, any change in market design principles such as increase in quantum of block bids needs to be studied in depth for better understanding and effective market monitoring.
Submitted for consideration of the Honorable Commission and further directions, if any.
सादर धन्यवाद,

भवदीय,
एस एस बड़पंडा
(एस.एस. बड़पंडा)
महाप्रबंधक

ANNEXURE 3

14-06-2017

All letters on Block Bids from NLDC to CERC to be taken out

Discussion Meeting
14^{th} June 2017

Akhilesh Awasthy
Director, Market Operations

Points for Discussion

- Difference between MCP and ACP when no Market Splitting (Letter ref. No.:- POSOCO/IEX/2017)
- Final ACV is greater than MCV in no. of days (Letter ref. No.:- POSOCO/IEX/2017/105)
- Impact of 100 MW Block Bid on Schedule and Ramping (Letter ref. No.:- POSOCO/IEX/2017/105)
- Treatment of Greenko Budhil Hydro Power Plant (Letter ref. No.:- POSOCO/MO/101)

Difference between MCP and ACP when no Market Splitting

Understanding the Cause with an Example
Case 1:- ACP>MCP with no Market Split

Portfolios	Bid Type	Quantity (MW) @ Price(Rs./kWhr)
Buyer-SR	Single	100@5, 90@5.50 to 6
Seller-SR	Single	-90@4 to 5, -100@5.5
Seller-SR	Single	-10@5
Seller-ER	Block	-10@3

- 2 Time Period Sets considered where above bids are available for both time sets
- Provisional result (with No Constrained)----

Time Set1

Price (Rs./kWhr) →		0	4	5	5.5	6
Buyer-SR	Single	100	100	100	90	90
Seller-SR	Single	0	-90	-90	-100	-100
Seller-SR	Single	0	0	-10	-10	-10
Seller-ER	Block	-10	-10	-10	-10	-10
Net (Buy-Sell)		90	0	-10	-30	-30

Time Set2

Price (Rs./kWhr) →		0	4	5	5.5	6
Buyer-SR	Single	100	100	100	90	90
Seller-SR	Single	0	-90	-90	-100	-100
Seller-SR	Single	0	0	-10	-10	-10
Seller-ER	Block	-10	-10	-10	-10	-10
Net (Buy-Sell)		90	0	-10	-30	-30

Provisional Result- MCP for both Time Blocks is Rs. 4/kWhr

Seller Block Bid will be selected since Sell Bid Price<Avg. MCP for both time sets.

Corridor Requisition in both time blocks from ER->SR is 10 MW.

Case 1:- ACP>MCP with no Market Split

Time Set	Requisition ER->SR	Availability in Exception report ER->SR
Set1	10	<10
Set2	10	>10

- Final Result (with Constrained)- Sell Block Bid will be rejected for both time sets.

Time Set 1; Congestion

Price (Rs./kWhr) →		0	4	5	5.5	6	6001
Buyer-SR	Single	100	100	100	90	90	0
Seller-SR	Single	0	-90	-90	-100	-100	-100
Seller-SR	Single	0	0	-10	-10	-10	-10
Net (Buy-Sell)		100	10	0	-20	-20	-110

Time Set 2; No Congestion

Price (Rs./kWhr) →		0	4	5	5.5	6
Buyer-SR	Single	100	100	100	90	90
Seller-SR	Single	0	-90	-90	-100	-100
Seller-SR	Single	0	0	-10	-10	-10
Seller-ER	Block	0	0	0	0	0
Net (Buy-Sell)		100	10	0	-20	-20

- For 2nd Time Set, there was no congestion and no market split but ACP(5/u)>MCP (4/u)

Case 2:- ACP<MCP with no Market Split

Portfolios	Bid Type	Quantity (MW) @ Price(Rs./kWhr)
Buyer-SR	Single	100@5, 90@5.5 to 6
Seller-SR	Single	-90@4 to 5, -100@5.5
Buyer-SR	Single	10@5.5
Buyer-ER	Block	10@7

- 2 Time Period Sets considered where above bids are available for both time sets
- Provisional result (with No Constrained)----

Time Set1

Price (Rs./kWhr) →		0	4	5	5.5	6	6001
Buyer-SR	Single	100	100	100	90	90	0
Seller-SR	Single	0	-90	-90	-100	-100	-100
Buyer-SR	Single	10	10	10	10	0	0
Buyer-ER	Block	10	10	10	10	10	10
Net (Buy-Sell)		120	30	30	10	0	-90

Time Set 2

Price (Rs./kWhr) →		0	4	5	5.5	6	6001
Buyer-SR	Single	100	100	100	90	90	0
Seller-SR	Single	0	-90	-90	-100	-100	-100
Buyer-SR	Single	10	10	10	10	0	0
Buyer-ER	Block	10	10	10	10	10	10
Net (Buy-Sell)		120	30	30	10	0	-90

Provisional Result- MCP for both Time Blocks is Rs. 6/kWhr

Buyer Block Bid will be selected since Buy Bid Price>Avg. MCP for both time sets.

Corridor Requisition in both time blocks from SR->ER is 10 MW.

Case 2:- ACP<MCP with no Market Split

Time Set	Requisition SR->ER	Availability in Exception report SR->ER
Set 1	10	<10
Set 2	10	>10

- Final Result (with Constrained)- Buy Block Bid will be rejected for both time sets.

Time Set 1; Congestion

Price (Rs./kWhr)	→	0	4	5	5.5	6
Buyer-SR	Single	100	100	90	90	90
Seller-SR	Single	0	-90	-90	-100	-100
Buyer-SR	Single	10	10	10	10	0
Net (Buy-Sell)		110	20	10	0	-10

Time Set 2; No Congestion

Price (Rs./kWhr)	→	0	4	5	5.5	6
Buyer-SR	Single	100	100	90	90	90
Seller-SR	Single	0	-90	-90	-100	-100
Buyer-SR	Single	10	10	10	10	0
Buyer-ER	Block	0	0	0	0	0
Net (Buy-Sell)		110	20	10	0	-10

- For 2nd Time Set there was no congestion and no market split but ACP(5.5/u)<MCP (4/u)

For Date 22nd May '17

- In 77th Time Block Exception Received, SR Import Required=1060.1 MW, Received=974.68 MW
- Change in Result for two block bids: -

Area Type	Bid Area	Bid Quantity	Bid Type	Duration of Time Block	Provisional/Final Status	Bid Price	Average System Price	Result
Deficit	S1	0.6	Buy	73-88	Provisional	3600	3591.71	Included
					Final	3600	3601.01	Excluded
Surplus	N2	7.3	Buy	79-80	Provisional	3800	3777.79	Paradoxically Rejected
					Final	3800	3790.25	Reincluded

Block	MCP	Exception Received	ACP-SR	ACP-RoI	Price Diff (ACP_{SR}-ACP_{RoI})	No Congestion but MCP<>ACP	Price Diff.
73	2469.78	No	2469.77	2469.77	0.00	MCP<>ACP	0.01
74	2459.61	No	2459.61	2459.61	0.00		0
75	2669.9	No	2669.9	2669.9	0.00		0
76	3235.29	No	3235.29	3235.29	0.00		0
77	3299.66	Yes	3423.73	3299.19	124.54		
78	3549.03	No	3549	3549	0.00	MCP<>ACP	0.03
79	3750.75	No	3775.5	3775.5	0.00	MCP<>ACP	-24.75
80	3804.82	No	3804.99	3804.99	0.00	MCP<>ACP	-0.17
81	3802.43	No	3802.42	3802.42	0.00	MCP<>ACP	0.01
82	3802.39	No	3802.38	3802.38	0.00	MCP<>ACP	0.01
83	3802.47	No	3802.46	3802.46	0.00	MCP<>ACP	0.01
84	4001.17	No	4001.16	4001.16	0.00	MCP<>ACP	0.01
85	4206.3	No	4206.29	4206.29	0.00	MCP<>ACP	0.01
86	4206.46	No	4206.45	4206.45	0.00	MCP<>ACP	0.01
87	4204.53	No	4204.51	4204.51	0.00	MCP<>ACP	0.02
88	4202.75	No	4202.73	4202.73	0.00	MCP<>ACP	0.02

Congestion Scenario (Jan-16 to June-17)

Month	No. of Blocks when Exception Received	% Time Block When Exception received	Avg. Volume Constraint in NR (MW)	Avg. Volume Constraint in SR (MW)
Jan_16	1918	64.45%	299	201
Feb_16	1698	60.99%	254	120
Mar_16	2362	79.37%	117	466
Apr_16	2518	87.43%	171	490
May_16	2507	84.24%	338	246
Jun_16	1629	56.56%	260	43
Jul_16	1270	42.67%	32	164
Aug_16	1507	50.64%	41	150
Sep_16	1399	48.58%	298	16
Oct_16	1569	52.72%	81	243
Nov_16	1869	64.90%	39	365
Dec_16	1868	62.77%	200	256
Jan_17	1998	67.14%	247	233
Feb_17	2100	78.13%	301	200
Mar_17	1761	59.17%	115	374
1st to 12th Apr'17	495	42.97%	0	198
13th to 30th Apr'17	1043	60.36%	0	441
May_17	392	13.17%	11	55
1st to 12th Jun'17	0	0.00%	0	0

- Congestion decreased this season.

Price Difference between MCP and ACP when there is no Market Splitting

Month	<10 paise	10-20 paise	20-30 paise	Difference greater than 30 paise	Total Blocks when MCP<>ACP with No Split	No. of Blocks when No Exception Received	Avg. Volume Constraint in NR (MW)	Avg. Volume Constraint in SR (MW)
Jan-16	582	42	25	13	**662**	1058	299	201
Feb-16	896	57	6	5	**964**	1086	254	120
Mar-16	586	9	1	0	**596**	614	117	466
Apr-16	319	27	8	6	**360**	362	171	490
May-16	400	36	10	8	**454**	469	338	246
Jun-16	674	47	10	18	**749**	1251	260	43
Jul-16	816	76	20	6	**918**	1706	32	164
Aug-16	805	75	33	26	**939**	1469	41	150
Sep-16	918	47	12	7	**984**	1481	298	16
Oct-16	672	22	3	1	**698**	1407	81	243
Nov-16	791	40	23	4	**858**	1011	39	365
Dec-16	690	14	18	7	**729**	1108	200	256
Jan-17	858	53	9	3	**923**	978	247	233
Feb-17	531	33	13	4	**581**	588	301	200
Mar-17	872	34	9	3	**918**	1215	115	374
1-12 Apr 17	322	20	1	0	**343**	657	0	198
13-31 Apr 17	515	39	8	4	**566**	685	0	441
May-17	621	30	4	4	**659**	2584	11	55
1-12 Jun 17	0	0	0	0	**0**	1152	0	0

Trend Analysis of MCP<>ACP when No Market Split

No Regular Pattern available since Jan-16, in May-17 reduced to 25.5%.

Month	Total no. of Blocks	No. of Blocks with No Congestion	Blocks with No Congestion but MCP<>ACP	% Blocks where MCP<>ACP out of total no. congestion blocks
Jan-16	2976	1058	662	62.57%
Feb-16	2784	1086	964	88.77%
Mar-16	2976	614	596	97.07%
Apr-16	2880	362	360	99.45%
May-16	2976	469	454	96.80%
Jun-16	2880	1251	749	59.87%
Jul-16	2976	1706	918	53.81%
Aug-16	2976	1469	939	63.92%
Sep-16	2880	1481	984	66.44%
Oct-16	2976	1407	698	49.61%
Nov-16	2880	1011	858	84.87%
Dec-16	2976	1108	729	65.79%
Jan-17	2976	978	923	94.38%
Feb-17	2688	588	581	98.81%
Mar-17	2976	1215	918	75.56%
1st to 12th Apr	1152	657	343	52.21%
13th to 30th Apr	1728	685	566	82.63%
May-17	2976	2584	659	25.50%
1 to 12th Jun 17	1152	1152	0	0.00%

Trend of Block Bids>50 MW with difference between MCP and ACP when No Congestion

Delivery Date	Total No. of Block Bids>50 MW	No. of Block Bids>50 MW selected in Provisional result	No. of Block Bids >50 MW Selected in Final result	No. of Block Bids>50 MW rejected in Provisional result	No. of Block Bids>50 MW rejected in Final result	Block Bids selected in Prov. but not final or vice-versa
13-Apr-2017	5	5	5	0	0	0
14-Apr-2017	16	10	10	6	6	0
15-Apr-2017	10	8	8	2	2	0
16-Apr-2017	7	6	6	1	1	0
17-Apr-2017	8	8	8	0	0	0
18-Apr-2017	12	10	10	2	2	0
19-Apr-2017	12	10	10	2	2	0
20-Apr-2017	9	9	9	0	0	0
21-Apr-2017	9	8	7	1	2	1
22-Apr-2017	10	9	9	1	1	0
23-Apr-2017	12	6	6	6	6	0
24-Apr-2017	9	9	9	0	0	0
25-Apr-2017	9	6	5	3	4	1
26-Apr-2017	42	33	33	9	9	0
27-Apr-2017	38	28	30	10	8	2
28-Apr-2017	46	24	28	22	18	4
29-Apr-2017	33	9	11	24	22	2
30-Apr-2017	13	4	4	9	9	0
01-May-2017	1	1	1	0	0	0
02-May-2017	17	12	12	5	5	0
03-May-2017	10	10	10	0	0	0
04-May-2017	11	11	11	0	0	0
05-May-2017	27	23	23	4	4	0
06-May-2017	36	31	31	5	5	0
07-May-2017	59	47	47	12	12	0

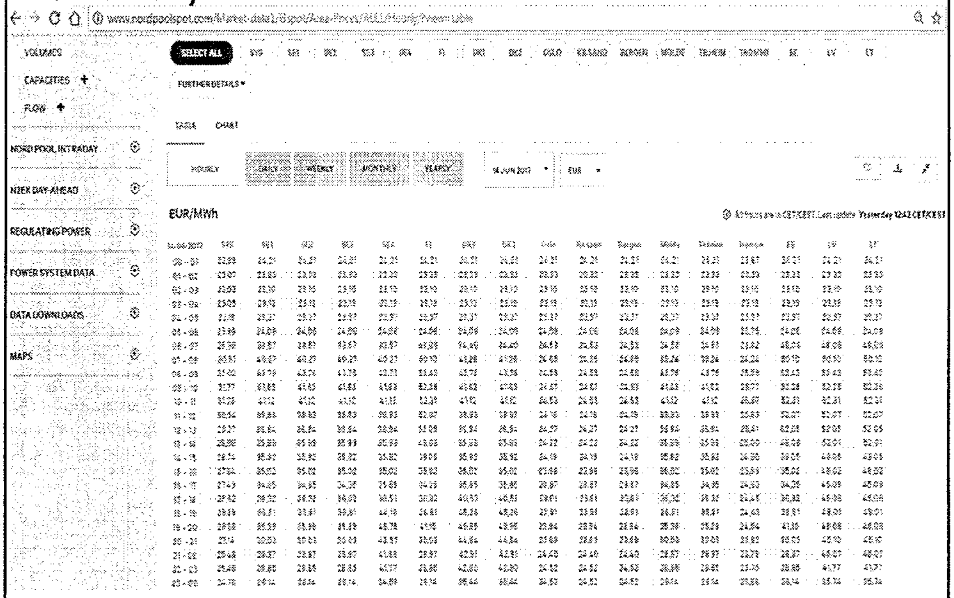
Trend of Block Bids>50 MW with difference between MCP and ACP when No Congestion

Delivery Date	Total No. of Block Bids>50 MW	No. of Block Bids>50 MW selected in Provisional result	No. of Block Bids >50 MW Selected in Final result	No. of Block Bids>50 MW rejected in Provisional result	No. of Block Bids>50 MW rejected in Final result	Block Bids selected in Prov. but not final or vice-versa
08-May-2017	41	33	32	8	9	1
09-May-2017	39	29	29	10	10	0
10-May-2017	67	49	49	18	18	0
11-May-2017	52	37	37	15	15	0
12-May-2017	75	56	56	19	19	0
13-May-2017	44	42	42	2	2	0
14-May-2017	50	45	45	5	5	0
15-May-2017	78	55	55	23	23	0
16-May-2017	63	57	57	6	6	0
17-May-2017	42	38	38	4	4	0
18-May-2017	64	44	44	20	20	0
19-May-2017	71	53	53	18	18	0
20-May-2017	74	55	55	19	19	0
21-May-2017	72	42	36	30	36	6
22-May-2017	55	41	41	14	14	0
23-May-2017	70	37	37	33	33	0
24-May-2017	62	55	55	7	7	0
25-May-2017	42	40	40	2	2	0
26-May-2017	41	39	39	2	2	0
27-May-2017	43	40	40	3	3	0
28-May-2017	53	29	29	24	24	0
29-May-2017	58	39	39	19	19	0
30-May-2017	65	32	31	33	34	1
31-May-2017	53	37	37	16	16	0
Average	**37.45**	**27.78**	**27.73**	**9.67**	**9.71**	**0.37**

Summary

- Two Reasons for Price Difference between MCP and ACP: -
- ➢ Exception and hence Market Split in a day
- ➢ Presence of Block Bid where bid size is not relevant but duration of block bids at margin are relevant.
- Due to exception received, the duration of Block Bids included/rejected (which are at margin) will determine the no. of 15-min. blocks where diff. between MCP and ACP will arise.

Nord Pool Spot Price for 14-06-17 (Hr. 01 to 05)



Final ACV is greater than MCV on no. of days

Understanding the Cause with an Example

Unconstrained Solution (Illustration with Single Bid)

Region 1
Sell Bid of 100 MW@ Rs. 3/unit
Buy Bid of 100 MW @ Rs. 4/Unit

100 MW ↓

Region 2
Buy Bid of 100 MW@ Rs. 7/unit
Sell Bid of 100 MW @ Rs. 6/Unit

Unconstrained MCP =Rs. 5 and MCV=100 MW

Price (Rs./kWhr)	⟶	0	2.99	3	4	4.01	5.99	6	7	7.01
Region 1 Sell Bid	100 @3/	0	0	-100	-100	-100	-100	-100	-100	-100
Region 1 Buy Bid	100@4/	100	100	100	100	0	0	0	0	0
Region 2 Buy Bid	100@7/	100	100	100	100	100	100	100	100	0
Region 2 Sell Bid	100@6/	0	0	0	0	0	0	-100	-100	-100
Net (Buy-Sell)		200	200	100	100	0	0	-100	-100	-200

Constrained Solution (0 Corridor from region 1 to region 2)

Region 1
Sell Bid of 100 MW@ Rs. 3/unit
Buy Bid of 100 MW @ Rs. 4/Unit

Price (Rs./kWhr)		0	2.99	3	4	4.01
Region 1 Sell Bid	100 @3/	0	0	-100	-100	-100
Region 1 Buy Bid	100@4/	100	100	100	100	0
Net (Buy-Sell)		100	100	0	0	-100

Region 1-
ACV - **100**
ACP- 3.5

Region 2
Buy Bid of 100 MW@ Rs. 7/unit
Sell Bid of 100 MW @ Rs. 6/Unit

Price (Rs./kWhr)		0	5.99	6	7	7.01
Region 2 Buy Bid	100@7/	100	100	100	100	0
Region 2 Sell Bid	100@6/	0	0	-100	-100	-100
Net (Buy-Sell)		100	100	0	0	-100

Region 2-
ACV - **100**
ACP- 6.5

- Sum of ACV 200 MW is greater than MCV of 100 MW
- Both Single and Block Bid can create such instances

Congestion and ACV>MCV

Delivery Date	No. of Blocks of Congestion	Volume Constraint in NR (MW)	Volume Constraint in SR (MW)	ACV>MCV (MWhr)
01/Feb/2017	82	419	130	323
02/Feb/2017	84	530	138	3155
03/Feb/2017	96	1118	209	709
04/Feb/2017	94	558	73	1460
05/Feb/2017	69	593	129	278
06/Feb/2017	77	527	115	3390
07/Feb/2017	57	208	130	1563
08/Feb/2017	37	151	26	2386
09/Feb/2017	67	294	95	3824
10/Feb/2017	83	173	168	671
11/Feb/2017	76	178	185	876
12/Feb/2017	95	263	240	146
13/Feb/2017	91	254	324	1032
14/Feb/2017	76	284	378	2005
15/Feb/2017	73	390	75	232
16/Feb/2017	75	520	64	112
17/Feb/2017	69	270	18	1265
18/Feb/2017	68	237	14	980
19/Feb/2017	60	196	19	537
20/Feb/2017	67	190	44	871
21/Feb/2017	72	106	164	1438
22/Feb/2017	89	148	267	1074
23/Feb/2017	75	229	317	839
24/Feb/2017	76	43	853	362
25/Feb/2017	76	209	530	124
26/Feb/2017	73	66	431	150
27/Feb/2017	72	136	278	237
28/Feb/2017	71	144	174	249

Delivery Date	No. of Blocks of Congestion	Volume Constraint in NR (MW)	Volume Constraint in SR (MW)	ACV>MCV (MWhr)
01/Mar/2017	76	478	225	185
02/Mar/2017	91	803	3	780
03/Mar/2017	78	305	63	880
04/Mar/2017	38	56	44	250
05/Mar/2017	5	16		112
06/Mar/2017	80	25	990	
07/Mar/2017	96	58	1131	65
08/Mar/2017	96	75	1221	
09/Mar/2017	96	222	1294	
10/Mar/2017	96	9	1182	
11/Mar/2017	96		1049	
12/Mar/2017	0			
13/Mar/2017	68		173	10
14/Mar/2017	40		115	125
15/Mar/2017	38	14	114	164
16/Mar/2017	76	207	786	776
17/Mar/2017	96	152	1002	422
18/Mar/2017	67	82	448	2152
19/Mar/2017	96	80	539	78
20/Mar/2017	95	138	609	312
21/Mar/2017	62	432	3	1271
22/Mar/2017	27	45	32	1874
23/Mar/2017	9	28		63
24/Mar/2017	46	338		1719
25/Mar/2017	8		5	2
26/Mar/2017	15		9	57
27/Mar/2017	31		37	42
28/Mar/2017	37		54	343
29/Mar/2017	0			
30/Mar/2017	58		278	360
31/Mar/2017	44		178	125

Congestion and ACV>MCV

Delivery Date	No. of Blocks of Congestion	Volume Constraint in NR (MW)	Volume Constraint in SR (MW)	ACV>MCV (MWhr)	Delivery Date	No. of Blocks of Congestion	Volume Constraint in NR (MW)	Volume Constraint in SR (MW)	ACV>MCV (MWhr)
01/Apr/2017	32		140.34	2002	01/May/2017	0			
02/Apr/2017	0				02/May/2017	0			
03/Apr/2017	0				03/May/2017	8	27.23		245
04/Apr/2017	33		69.97	13	04/May/2017	57	130.68	92.61	744
05/Apr/2017	10		14.02	482	05/May/2017	70		402.58	800
06/Apr/2017	33		75.53	760	06/May/2017	17		49.12	
07/Apr/2017	0				07/May/2017	27	16.09	64.75	943
08/Apr/2017	68		499.29	1022	08/May/2017	14	0.73	9.54	9
09/Apr/2017	79		282.56	189	09/May/2017	13		14.57	70
10/Apr/2017	80		368.36	898	10/May/2017	15		100.13	286
11/Apr/2017	85		420.43	394	11/May/2017	0			
12/Apr/2017	75		509.18	473	12/May/2017	0			
13/Apr/2017	64		405.56	662	13/May/2017	0			
14/Apr/2017	69		385.94	495	14/May/2017	26	22.69	40.29	807
15/Apr/2017	46		185.11	1036	15/May/2017	8	61.45		419
16/Apr/2017	53		195.00	186	16/May/2017	9		5.63	5
17/Apr/2017	85		785.22	416	17/May/2017	52	67.82	113.69	340
18/Apr/2017	82		533.28	504	18/May/2017	0			
19/Apr/2017	84		868.74	2176	19/May/2017	0			
20/Apr/2017	90		959.24	1139	20/May/2017	0			
21/Apr/2017	81		907.57	789	21/May/2017	72		792.07	1263
22/Apr/2017	70		887.18	2091	22/May/2017	1		0.89	2
23/Apr/2017	30		51.29	62	23/May/2017	0			
24/Apr/2017	0				24/May/2017	0			
25/Apr/2017	43		137.87	21	25/May/2017	0			
26/Apr/2017	55		286.95	743	26/May/2017	0			
27/Apr/2017	46		316.54	2494	27/May/2017	0			
28/Apr/2017	44		252.42	2041	28/May/2017	0			
29/Apr/2017	35		92.44	2342	29/May/2017	0			
30/Apr/2017	66		687.60	1012	30/May/2017	3		3.82	
					31/May/2017	0			

Impact of 100 MW Block Bid on Schedule and Ramping

No. of Block Bids>50 MW

Delivery Date	Total no. of Bids	No. of Single Bids	No. of Block Bids	Blocks Bids with Bid Qty. >50 MW	% Block Bids with Q>50 MW to total no. of block bids
13-Apr-17	4425	461	3964	5	0.13%
14-Apr-17	4301	456	3845	16	0.42%
15-Apr-17	4102	451	3651	10	0.27%
16-Apr-17	3900	420	3480	7	0.20%
17-Apr-17	4165	456	3709	8	0.22%
18-Apr-17	4413	470	3943	12	0.30%
19-Apr-17	4433	471	3962	12	0.30%
20-Apr-17	4265	479	3786	9	0.24%
21-Apr-17	4316	480	3836	9	0.23%
22-Apr-17	4351	477	3874	10	0.26%
23-Apr-17	3978	443	3535	12	0.34%
24-Apr-17	4328	470	3858	9	0.23%
25-Apr-17	4590	488	4102	9	0.22%
26-Apr-17	4613	491	4122	42	1.02%
27-Apr-17	4497	489	4008	38	0.95%
28-Apr-17	4453	472	3981	46	1.16%
29-Apr-17	4220	474	3746	33	0.88%
30-Apr-17	3879	437	3442	13	0.38%
1-May-17	3186	328	2858	1	0.03%
2-May-17	3751	371	3380	17	0.50%
3-May-17	4196	443	3753	10	0.27%
4-May-17	4095	441	3654	11	0.30%
5-May-17	4074	428	3646	27	0.74%
6-May-17	4248	441	3807	36	0.95%
7-May-17	3968	399	3569	59	1.65%

Delivery Date	Total no. of Bids	No. of Single Bids	No. of Block Bids	Blocks Bids with Bid Qty. >50 MW	% Block Bids with Q>50 MW to total no. of block bids
8-May-17	4131	428	3703	41	1.11%
9-May-17	4167	425	3742	39	1.04%
10-May-17	4340	434	3906	67	1.72%
11-May-17	4472	449	4023	52	1.29%
12-May-17	4437	458	3979	75	1.88%
13-May-17	4320	440	3880	44	1.13%
14-May-17	3916	421	3495	50	1.43%
15-May-17	4082	443	3639	78	2.14%
16-May-17	4414	438	3976	63	1.58%
17-May-17	4415	452	3963	42	1.06%
18-May-17	4485	452	4033	64	1.59%
19-May-17	4358	461	3897	71	1.82%
20-May-17	4280	467	3813	74	1.94%
21-May-17	4105	435	3670	72	1.96%
22-May-17	4219	446	3773	55	1.46%
23-May-17	4391	451	3940	70	1.78%
24-May-17	4360	462	3898	62	1.59%
25-May-17	4412	455	3957	42	1.06%
26-May-17	4399	450	3949	41	1.04%
27-May-17	4361	442	3919	43	1.10%
28-May-17	4127	420	3707	53	1.43%
29-May-17	4253	445	3808	58	1.52%
30-May-17	4292	452	3840	65	1.69%
31-May-17	4427	461	3966	53	1.34%
Average	**4243**	**447**	**3796**	**37**	**0.98%**

No. of Portfolios with Block Bids>50 MW

Delivery Date	Total no. of Portfolios	No. of Portfolios with Single Bids	No. of Portfolio with Block Bids	No. of Portfolios with Blocks Bids Qty. >50 MW	% Block Bids Q>50 MW to total no. of Block Bids
13-Apr-17	1127	461	704	1	0.14%
14-Apr-17	1118	456	697	3	0.43%
15-Apr-17	1129	451	708	4	0.56%
16-Apr-17	1061	420	667	3	0.45%
17-Apr-17	1092	456	665	3	0.45%
18-Apr-17	1145	470	707	4	0.57%
19-Apr-17	1147	471	712	4	0.56%
20-Apr-17	1145	479	699	3	0.43%
21-Apr-17	1136	480	690	3	0.43%
22-Apr-17	1144	477	704	4	0.57%
23-Apr-17	1072	443	664	3	0.45%
24-Apr-17	1101	470	668	3	0.45%
25-Apr-17	1166	488	714	4	0.56%
26-Apr-17	1173	491	717	4	0.56%
27-Apr-17	1178	489	725	4	0.55%
28-Apr-17	1139	472	703	6	0.85%
29-Apr-17	1138	474	700	4	0.57%
30-Apr-17	1058	437	649	2	0.31%
1-May-17	835	328	529	1	0.19%
2-May-17	923	371	580	3	0.52%
3-May-17	1042	443	626	2	0.32%
4-May-17	1042	441	627	2	0.32%
5-May-17	973	428	572	7	1.22%
6-May-17	1004	441	592	6	1.01%
7-May-17	941	399	571	6	1.05%

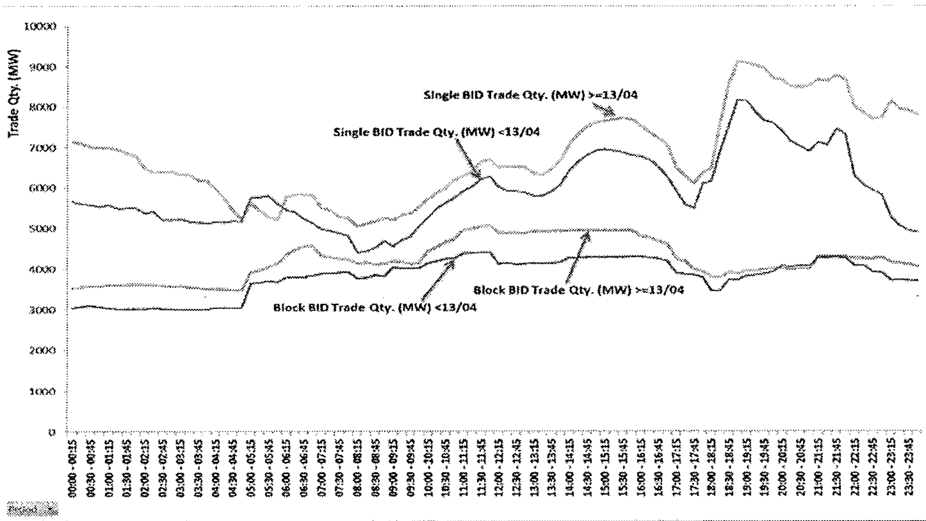
Delivery Date	Total no. of Portfolios	No. of Portfolios with Single Bids	No. of Portfolio with Block Bids	No. of Portfolios with Blocks Bids Qty. >50 MW	% Block Bids Q>50 MW to total no. of Block Bids
8-May-17	975	428	579	5	0.86%
9-May-17	970	425	572	6	1.05%
10-May-17	1020	434	615	7	1.14%
11-May-17	1082	449	661	6	0.91%
12-May-17	1090	458	663	8	1.21%
13-May-17	1045	440	633	7	1.11%
14-May-17	989	421	597	7	1.17%
15-May-17	1016	443	606	7	1.16%
16-May-17	999	438	595	9	1.51%
17-May-17	1035	452	613	8	1.31%
18-May-17	1054	452	633	9	1.42%
19-May-17	1041	461	610	9	1.48%
20-May-17	1056	467	616	8	1.30%
21-May-17	998	435	590	7	1.19%
22-May-17	1021	446	603	5	0.83%
23-May-17	1027	451	602	5	0.83%
24-May-17	1043	462	609	6	0.99%
25-May-17	1038	455	612	4	0.65%
26-May-17	1011	450	591	5	0.85%
27-May-17	989	442	576	5	0.87%
28-May-17	971	420	581	6	1.03%
29-May-17	999	445	584	7	1.20%
30-May-17	1025	452	604	8	1.32%
31-May-17	1056	461	628	5	0.80%
Average	**1053**	**447**	**636**	**5**	**0.81%**

Quantity Selection of Block Bids>50 MW

Delivery Date	Total Trade Qty. (MUs)	Single Bid Trade Qty. (MUs)	Block Bid Trade Qty. (MUs)	Block Bid Trade Qty. with Bid >50 MW(MUs)	% Block Bids Q>50 MW to total no. of Block Bids
13-Apr-17	225	134	91	7	7.73%
14-Apr-17	232	135	97	10	9.90%
15-Apr-17	254	156	98	8	8.49%
16-Apr-17	187	106	81	6	7.04%
17-Apr-17	228	139	90	8	8.65%
18-Apr-17	263	160	102	12	11.83%
19-Apr-17	298	183	116	12	10.66%
20-Apr-17	316	200	116	12	10.60%
21-Apr-17	297	184	113	10	9.15%
22-Apr-17	293	169	124	10	7.65%
23-Apr-17	238	157	81	5	6.49%
24-Apr-17	272	172	100	11	11.38%
25-Apr-17	258	163	95	7	7.49%
26-Apr-17	260	149	111	29	25.89%
27-Apr-17	268	160	109	25	23.35%
28-Apr-17	261	147	113	22	19.61%
29-Apr-17	264	155	109	10	9.15%
30-Apr-17	262	137	125	2	1.40%
1-May-17	229	132	96	2	1.90%
2-May-17	263	149	114	7	5.83%
3-May-17	257	148	109	6	5.75%
4-May-17	225	156	69	4	6.34%
5-May-17	245	157	89	7	7.96%
6-May-17	258	168	90	8	8.88%
7-May-17	281	158	123	13	10.24%

Delivery Date	Total Trade Qty. (MUs)	Single Bid Trade Qty. (MUs)	Block Bid Trade Qty. (MUs)	Block Bid Trade Qty. with Bid >50 MW(MUs)	% Block Bids Q>50 MW to total no. of Block Bids
8-May-17	297	174	123	14	11.13%
9-May-17	256	156	100	10	9.58%
10-May-17	256	148	108	19	17.38%
11-May-17	260	156	104	9	8.31%
12-May-17	281	175	106	13	12.70%
13-May-17	297	175	122	10	8.30%
14-May-17	270	161	108	12	11.46%
15-May-17	304	178	126	15	12.10%
16-May-17	286	169	117	14	11.88%
17-May-17	288	173	115	13	11.17%
18-May-17	296	173	122	13	10.95%
19-May-17	295	171	124	18	14.77%
20-May-17	289	178	111	12	10.74%
21-May-17	231	142	89	6	6.61%
22-May-17	287	174	113	10	8.51%
23-May-17	267	175	92	8	9.08%
24-May-17	255	159	96	20	21.13%
25-May-17	252	164	88	9	10.39%
26-May-17	273	185	88	9	10.06%
27-May-17	278	179	100	10	10.22%
28-May-17	203	133	70	3	4.20%
29-May-17	254	176	78	8	10.84%
30-May-17	241	166	75	13	17.50%
31-May-17	236	161	75	16	20.83%
Average	**263**	**161**	**102**	**11**	**10.68%**

Trade Pattern Analysis on Time Block Basis

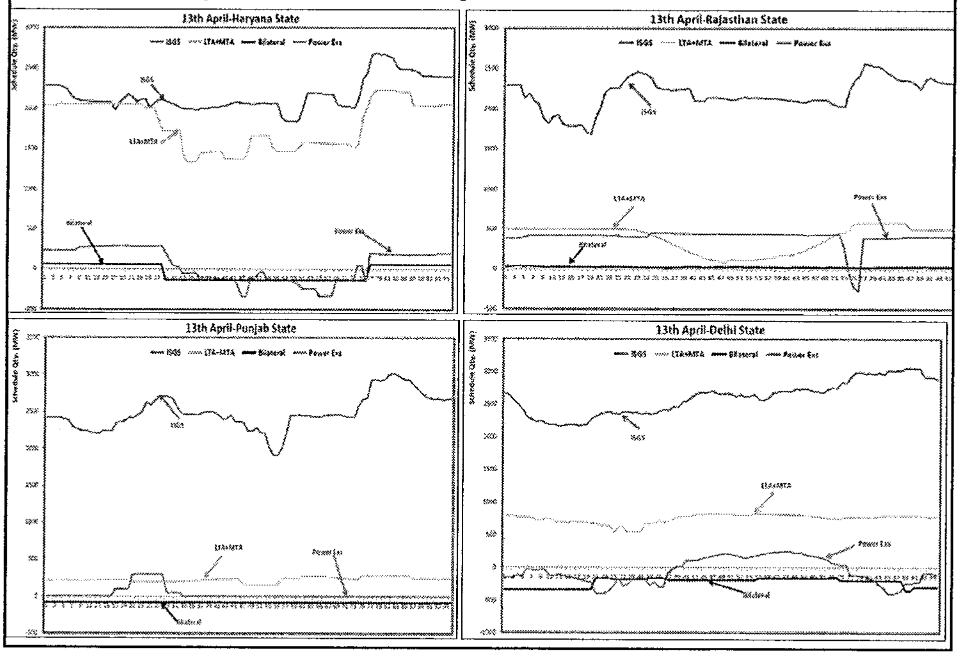


<< Time Block wise analysis of Single Bid and Block Bid Selected Qty. for two time periods-
i) <13/04=For Period 08/04 to 12/04 (-5 days) (ii)>=13/04=For Period 13/04 to 17/04 (+5 days)
Depicts that Block Bid has smooth curve as compared to Single Bid Curve.

Ramping Analysis of IEX Trade at State Level

- Analyzed for States in NR Region- Haryana, Rajasthan, Punjab, Delhi and UP.
- State's PXs Schedule compared with ISGS, LTA+MTA and Bilateral Transaction.
- Analysis Period-8th to 17th April (-5 to +5 days)
- <<Excel Sheet-Ramping North Region will be hyper linked>>

For Sample Date-13th April



Treatment of Greenko Budhil Hydro Power Plant

Letter Query Points

- Query a) NoC has been issued to M/s Greenko Budhil by NRLDC and no NoC has been issued for sale of power by HP State at M/s Greenko Budhil Periphery.
- Query b) Power presently is being sold by two different grid connected entities i.e. HP state and M/s Greenko Budhil from the same generator periphery
- Query c) Any grid connected can sell or buy power at his own grid periphery only.

Status of Greenko Budhil

- The Budhil Hydro Electric Project (BHEP) is a run-of-the river hydro project in the Chamba district of the state of Himachal Pradesh in India. The project having an installed capacity of 70MW has been in operation since May 2012.

- The Power Plant is a Regional Entity and as per Procedure for Scheduling of Collective Transactions:-

  All Entities, whose metering and energy accounting is presently carried out by Regional Load Despatch Centres (RLDCs)/Regional Power Committees (RPCs) shall be deemed to be Regional Entities of the respective Region. Any new Entity, who satisfies the conditions for scheduling by Regional Load Despatch Centres, as per Indian Electricity Grid Code, 2006 and amendments thereof, and is intending to participate in trade through Power Exchange, as a Regional Entity shall obtain prior approval from the respective RLDCs/RPCs, by making an application.

- NRLDC Letter received on Date 25th Sep 2012 and after confirmation mail from NLDC, Budhil started trading from 27th Sep 2012 onwards at IEX Platform. Extract of NRLDC Letter:-

  It shall be ensured that total schedule of plant under all categories of transaction i.e. Long-term, Medium term open access (MTOA), STOA (bilateral) and STOA (PX) shall be within above limit. The station would also be following all the other rules and regulations as specified in various regulations of the Hon'ble CERC.

- The project after acquired from Lanco group is being referred as Greenko Budhil Hydro Power Private Limited. IEX received ROC, GoI and changed the name from 31st May'15 onwards.

Treatment of Greenko Budhil Power Plant

- As per Himachal Pradesh Hydro Policy 2006, Greenko Budhil Hydro Plant is providing Royalty Power of 12% for water usage in shape of free power to GoHP.

  25 Years of Agreement between GoHP and PTC India to sale the free power of Royalty through PTC India.

- For Regional Entity Generator M/s Budhil Hydro Power Plant, two Seller Clients:-
  i. Client Greenko Budhil thru Member NETS to trade 61.60 MW
  ii. Client GoHP (12% free power thru Greenko Budhil) thru Member PTC to trade 8.40 MW

- Extracts from IEX Business Rules:-

  18. Dealing with Clients 18.1 There are two categories of Clients for Electricity Contracts.

  ***a. Grid-connected Client:** A Client who is eligible to buy or sell electricity and is connected to the grid. The entities including but not limited to, Distribution Licensees, Generators, Consumers and Open Access Users can become Grid connected Clients.*

  ***b. Trader Client:** A Client who is eligible to trade in electricity under the Electricity Act, 2003 and has a legally valid power purchase/sale agreement, which gives the Client the right to purchase and sell electricity. A Trader Client will register each power purchase/sale agreement with the Member who will be registering the same with the Exchange and receive a separate registration identification code. The entities such as trading licensees can become Trader Clients*

Treatment of Greenko Budhil Power Plant

- Budhil Hydro Power is the Grid Connected Entity for which NoC by NRLDC, Scheduling by NRLDC and Settlement by NRPC is happening.

Thank You

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ANNEXURE 4

INDIAN ENERGY EXCHANGE

Ref No.: IEX/CERC/MO/17-18/014 **24th July 2017**

To,
The Secretary,
Central Electricity Regulatory Commission,
3rd & 4th Floor, Chanderlok Building,
36, Janpath, New Delhi – 110 001

Subject: - Increase in Maximum Quantity of Block Bid from 50 to 100 MW

Reference: - (i) POSOCO letter with Ref. No. POSOCO/NLDC/IEX/2017/105 on date 28th April'17
(ii)POSOCO letter with Ref. No. POSOCO/NLDC/IEX/2017 on date 19th May'17
(iii) POSOCO letter with Ref. No. POSOCO/MO/101 on date 8th June'17

Dear Sir,

In reference to above letters received from M/s POSOCO, hon'ble CERC had arranged a meeting on date 14th June 2017 to discuss following agenda points:-

a) Increase of Block Bid maximum size from 50 MW to 100 MW and its performance.
b) Reason(s) for Price Difference between Market Clearing Price and Area Clearing Price(s) in no congestion blocks.
c) Reason(s) for Final Cleared Volume greater than Market Clearing Volume on number of days.
d) Impact of increase in block bid size in Scheduling and Ramping.
e) Explanation on M/s Greenko Budhil Hydro Power Plant

Detailed presentation was made on date 14th June 17 to the staff of hon'ble Commission along with officials of NLDC on first four agenda points, however item (e) could not be discussed in the meeting due to paucity of time.

In order to evaluate the performance of Block Bid with size greater than 50 MW, data set in the meeting was taken for 49 days (13th April to 31st May '17), which has now been updated for a larger time frame i.e. for 79 days (13th April to 30th June '17).

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Further since the last agenda point could not be discussed the same has been explained in detail and attached as annexure to this letter. Also as desired in the meeting following additional information asked for has also been included in the note:-

a) Letter from M/s NVVNL Ltd. for increasing the Block Bid Size
b) Test Summary Report
c) Schedule Ramping Status of States putting Block Bid Size greater than 50 MW

Block Bid Size in other International Market(s) is mentioned as below:-

Electricity Market	Countries	Max. Block Bid Size (MW)	Annual Trade (TWhr)
EPEX DE/AT	Germany/ Austria	600	229 (Jun'16-Jul'17)
EPEX FR	France	600	105 (Jun'16-Jul'17)
Nord Pool	Nordic & Baltic Countries	500	390 (Jan'16-Dec'16)
N2EX UK	United Kingdom	500	108 (Jan'16-Dec'16)
EPEX NL	Netherlands	400	32 (Jun'16-Jul'17)
EPEX BL	Belgium	400	20 (Jun'16-Jul'17)
EPEX CH	Switzerland	150	23 (Jun'16-Jul'17)
IEX	India	100	42 (Jun'16-Jul'17)

We would be happy to respond for any more queries in this respect.

Thanking you,

Yours Faithfully

Akhilesh Awasthy
Director (Market Operations)

Cc:- HOD, Market Operations, POSOCO, Katwaria Sarai, New Delhi

Annexure-I

Increase of Block Bid maximum size from 50 MW to 100 MW and its performance- IEX vide its Circular No. 237 dated 11th April 2017 has increased the Block Bid Size from 50 MW to 100 MW from trading date 12th April 2017. This change was made on the request of members of IEX, so that they can have efficient power plant management and load management of Discoms. (Copy of letter received from M/s NVVNL is attached as Annexure-IA). Functional and Performance testing was conducted and test summary report for the same is attached as Annexure-IB.

Post successful testing, the Circular was issued and posted at our website on date 11th April 2017.

The impact of Block Bid>50 MW was analyzed for 79 days which is as under:-

i) On an average only 7 portfolios out of 1040 portfolios are putting block bid>50 MW. Also total number of portfolios who have used this facility till 30th June is 34. Daily status is attached as Annexure IC.

ii) On an average 68 number of Block Bids were submitted with quantity>50 MW out of 3825 number of block bids. Daily status is attached as Annexure ID.

It may be seen under Annexure IE that most of the time these bids are not the marginal bids which get affected due to congestion, as such the results would not have changed had the client submitted two bids of say 50 MW each in place of a single 100 MW Block bid.

Impact of this change on the prices or clearing volume (both unconstrained and constrained), as shown in Annexures indicates that there is no adverse impact on these results. Further discussion on these issues is in the subsequent Annexures.

<u>**Annexure-II**</u>

Reason(s) for Price Difference between Market Clearing Price and Area Clearing(s) in no congestion blocks- In the presentation the reason for such changes was explained with an example and also the same was illustrated with the Day-Ahead Market results for date 22nd May 2017, the same is reproduced as under:-

(i) Due to Congestion in some of the blocks of the day there might be a possibility in change in the prices of non-congested blocks might as well. If there is no congestion and hence no market split in any of the time blocks of the day such situation will not arise.

(ii) Presence of marginal Block Bid in bid set results in such situations, which gets manifested when congestion occurs. It may be noted that the bid size is not the only reason for such occurrence, however number of blocks in which such bids at margin is present is more relevant. Due to congestion in certain blocks of the day, the demand and supply situation changes not only in congested time blocks but also in congestion free time blocks, due to inclusion of earlier rejected or rejection of earlier included marginal block bids, in both congested and non-congested time blocks. This may result in price difference between MCP and ACPs in congested as well as non-congested time blocks.

In this respect data in Annexure-IIA needs to be analyzed, where on several days the Block Bid with quantity >50 MW has not changed its status (i.e. Block Bid selected in Provisional remained selected in Final and/or Block Bid rejected in Provisional remained rejected in Final) in Provisional and Final results but still difference in MCP and ACPs has been noted in uncongested blocks.

As such the occurrences of Price difference between MCP and ACPs in uncongested blocks is not entirely associated with increase in Block Bid size. This has happened in the past as well when block bid size was maximum up to 50 MW. The monthly trend is attached as Annexure-IIB.

This phenomenon is neither counter-intuitive nor against power market regulations because in Day-Ahead Market the price results can be described under two outcomes:-

i) In case of no congestion and hence no market split in any time block of the day the MCP is relevant and Area Clearing Price(s) of Bid Area will always be equal to MCP.

ii) In case of congestion and hence market split in any time block of the day the ACP will be relevant for the day with following demarcation:-

- For congested time blocks of the day, the Area Clearing Prices will be different, for upstream and downstream of Congestion. Generally ACPs would be lower in surplus area as compared to MCP and higher in deficit area as compared to MCP, however in some special cases ACPs can be higher in Surplus area as compared to MCP or vice versa for the deficit area.
- For non-congested time blocks of the day, the Area Clearing Prices will be same for all price areas.

Such situations occur in other international day-ahead spot market as well. Sample for Nord Pool for date 14th June' 17 (from 0100 to 0500 hours) is produced as below. It may be seen that although in all price areas ACPs are same indicating no congestion for the above mentioned time blocks, however system price i.e. MCP ("SYS" price) is different from ACPs.

Website Link:- http://www.nordpoolspot.com/Market-data1/Elspot/Area-Prices/ALL1/Hourly/?view=table

TABLE CHART

HOURLY DAILY WEEKLY MONTHLY YEARLY 14 JUN 2017 EUR

EUR/MWh All hours are in CET/CEST Last update: Today 12:42 CET/CEST

14-06-2017	SYS	SE1	SE2	SE3	SE4	FI	DK1	DK2	Oslo	Kr.sand	Bergen	Molde	Tr.heim	Tromsø	EE	LV	LT
00 - 01	23.99	24.21	24.21	24.21	24.21	24.21	24.21	24.21	24.21	24.21	24.21	24.21	24.21	23.67	24.21	24.21	24.21
01 - 02	23.07	23.33	23.33	23.33	23.33	23.33	23.33	23.33	23.33	23.33	23.33	23.33	23.33	23.33	23.33	23.33	23.33
02 - 03	23.03	23.10	23.10	23.10	23.10	23.10	23.10	23.10	23.10	23.10	23.10	23.10	23.10	23.10	23.10	23.10	23.10
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
04 - 05	23.18	23.37	23.37	23.37	23.37	23.37	23.37	23.37	23.37	23.37	23.37	23.37	23.37	23.37	23.37	23.37	23.37
05 - 06	23.96	24.06	24.06	24.06	24.06	24.06	24.06	24.06	24.06	24.06	24.06	24.06	24.06	23.75	24.06	24.06	24.06
06 - 07	25.99	33.57	33.57	33.57	33.57	48.06	34.40	34.40	24.53	24.53	24.53	24.53	24.53	23.82	48.06	48.06	48.06
07 - 08	30.51	40.27	40.27	40.27	40.27	50.10	41.26	41.26	24.65	24.65	24.65	39.24	39.24	24.24	50.10	50.10	50.10
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
09 - 10	31.77	41.63	41.63	41.63	41.63	52.38	41.63	41.63	24.61	24.61	24.61	41.63	41.63	26.77	52.38	52.38	52.38
10 - 11	31.36	41.12	41.12	41.12	41.12	52.31	41.12	41.12	24.53	24.53	24.53	41.12	41.12	25.67	52.31	52.31	52.31
11 - 12	30.54	39.93	39.93	39.93	39.93	52.07	39.93	39.93	24.19	24.19	24.19	39.93	39.93	25.63	52.07	52.07	52.07
12 - 13	29.27	36.94	36.94	36.94	36.94	52.05	36.94	36.94	24.27	24.27	24.27	36.94	36.94	25.41	52.05	52.05	52.05
13 - 14	28.99	35.99	35.99	35.99	35.99	48.08	35.99	35.99	24.22	24.22	24.22	35.99	35.99	25.00	48.08	52.01	52.01
14 - 15	28.74	35.92	35.92	35.92	35.92	39.05	35.92	35.92	24.19	24.19	24.19	35.92	35.92	24.90	39.05	49.05	49.05
15 - 16	27.64	35.02	35.02	35.02	35.02	35.02	35.02	35.02	23.96	23.96	23.96	35.02	35.02	23.99	35.02	48.02	48.02
16 - 17	27.49	34.35	34.35	34.35	35.85	34.35	35.85	35.85	23.87	23.87	23.87	34.35	34.35	24.63	34.35	45.09	45.09
17 - 18	28.62	36.32	36.32	36.32	39.56	36.32	40.53	40.53	23.61	23.61	23.61	36.32	36.32	24.45	36.32	45.08	45.08
18 - 19	29.39	36.81	36.81	36.81	44.13	36.81	45.26	45.26	23.91	23.91	23.91	36.81	36.81	24.43	36.81	48.01	48.01
19 - 20	29.36	35.39	35.39	35.39	48.75	41.15	49.95	40.95	23.94	23.94	23.94	35.39	35.39	24.64	41.15	48.08	48.06
20 - 21	27.14	30.03	30.03	30.03	43.57	30.03	44.64	44.64	23.69	23.69	23.69	30.03	30.03	20.82	30.03	45.10	45.10
21 - 22	25.49	28.97	28.97	28.97	41.88	28.97	42.91	42.91	24.40	24.40	24.40	28.97	28.97	23.79	28.97	45.07	45.07
22 - 23	25.48	28.85	28.85	28.85	41.77	28.85	42.80	42.80	24.52	24.52	24.52	28.85	28.85	23.75	28.85	41.77	41.77
23 - 00	24.78	26.14	26.14	26.14	34.59	26.14	35.44	35.44	24.52	24.52	24.52	26.14	25.14	23.68	26.14	35.74	35.74

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Annexure-III

Reason(s) for Final Cleared Volume greater than Market Clearing Volume on number of days- In the presentation it was explained that such occurrences would take place when there is Congestion and hence Market Split in the day. For no congestion and hence no market split in any time block of the day such situation will not happen.

Due to congestion, the change in prices in Upstream and Downstream of congestion may result in final ACV being greater than MCV. This may happen due to selection of buy Single Bid and/or Block Bid in the Upstream which were rejected in unconstrained results and selection of Sell Single Bid and/or Block Bid in downstream of Congestion, which were rejected in unconstrained results.

Such occurrence(s) have also been noted in past and no direct relation between increase in Block Bid size and such occurrences were evident. In this case the size of block bid is not the only relevant factor which can be easily examined under Annexure-IIIA where on several days the Block Bid with quantity >50 MW has not changed its status in provisional and final results but still the situation where ACV>MCV had occurred.

In Nord Pool Spot Day-Ahead Market also such incidences have been noticed.

As such these occurrences is neither counter-intuitive nor has any direct has relation with change in the size of Block Bid.

Annexure-IV

Impact of increase in block bid size in Scheduling and Ramping: - In reference to the letter No. POSOCO/NLDC/IEX/2017/105 vide which it was observed that increase in block bid size may adversely impact the ramping profile. In this regard following may please be noted:-

i) The market size of collective transactions is merely 3%. For a particular participant there are various possibilities to meet their requirement of buying/selling under LTA and MTOA and in Short-term Bilateral and Collective transactions. It was shown in the presentation that ramping in schedules of Northern region states like Haryana, Rajasthan, Punjab and Delhi is insignificant in collective transactions as compared to other contract types. Currently State utility & Discoms of Delhi, Punjab, Uttarakhand, Maharashtra, Gujarat, Madhya Pradesh, DNH and West Bengal are putting block bid with greater than 50 MW. The Scheduling Ramping of these states is represented under Annexure IVA.

It may be seen that in case of these states as well, the schedule ramping in collective transactions as compared to other transactions is insignificant. In fact in many cases ramping in the Collective Transactions is seen as nullifying severe ramping of other transactions, thus improving overall ramping profile.

ii) It was demonstrated that for overall Schedule of any particular day, schedule through block bids has better ramping profile as compared to the ramping profile of selected single bids. A block bid is used by a participant for the procurement or sale of power which is specific to several blocks of period, while single bid allows partial execution of bids hence a block bid will have no ramping for those block of hours as compared to the single bid. Under Annexure IVB, Analysis of Single bid trade quantity vs. Block bid trade quantity for a 3 day period before and after the date on which Block Bid size was increased i.e. from 10th to 12th April and 13th to 15th April, establishes this assertion. As such the change in maximum quantity of Block Bid has no adverse impact on the ramping profile.

Annexure-V

Explanation on M/s Greenko Budhil Hydro Power Plant: - Due to paucity of time this agenda point could not be discussed in the meeting. In the letter no. POSOCO/MO/101 dated 8th June '17 it was mentioned that NoC to M/s Greenko Budhil was issued by NRLDC and no NoC was issued for sale of power by HP State at M/s Greenko Budhil Periphery, but power presently is being sold by two different grid connected entities i.e. M/s HP state and M/s Greenko Budhil from the same generator periphery. The explanation in this regards is mentioned as under:-

i) Status of Plant-Budhil Hydro Electric Project (now Greenko Budhil Hydro Power Private Limited) is a Regional Entity and as per "Procedure for Scheduling of Collective Transactions" it obtained first NoC for 70 MW quantity from NRLDC on date 25th Sep 2012 and started trading from 27th Sep 2012 onwards at IEX Platform, extract of NRLDC Letter is as below:-

It shall be ensured that total schedule of plant under all categories of transaction i.e. Long-term, Medium term open access (MTOA), STOA (bilateral) and STOA (PX) shall be within above limit. The station would also be following all the other rules and regulations as specified in various regulations of the Hon'ble CERC.

At Generator level, the plant export limit is therefore set as per the quantity specified in NoC from NRLDC.

ii) As per Himachal Pradesh Hydro Policy 2006, this Plant is providing Royalty Power of 12% for water usage as free power to GoHP, who have appointed a trading Licensee (M/s PTC India Ltd.) to sell this Royalty Power.

iii) To understand the treatment given to this royalty power we would like to draw your attention to Clause 18 of IEX Business Rules which is reproduced as under:-

18. Dealing with Clients 18.1 There are two categories of Clients for Electricity Contracts.

***a. Grid-connected Client:** A Client who is eligible to buy or sell electricity and is connected to the grid. The entities including but not limited to,* *Distribution Licensees, Generators, Consumers and Open Access Users can become Grid connected Clients.*

b. Trader Client: *A Client who is eligible to trade in electricity under the Electricity Act, 2003 and has a legally valid power purchase/sale agreement, which gives the Client the right to purchase and sell electricity. A Trader Client will register each power purchase/sale agreement with the Member who will be registering the same with the Exchange and receive a separate registration identification code. The entities such as trading licensees can become Trader Clients.*

Therefore for the generator M/s Greenko Budhil Power Plant with 70 MW allowed quantum, two clients are selling the power of the generator-

a) Grid Connected Client-M/s Greenko Budhil Power Plant;
b) Trader Client: - PTC selling royalty power of GoHP.

NoC issued by the generator M/s Greenko Budhil Power Plant (within the overall quantity limit permitted by NRLDC to this regional entity to sell the electricity generated) provides the bifurcation of quantity limit for the above two clients.

This arrangement is done as per hon'ble CERC approved Business Rules where a generator can sell its power by registering more than one client depending upon its commercial/regulatory requirements. Same practice is followed for other generators as well e.g. Allian Duhangan Hydro Power Project, Meenakshi Energy Limited, Karcham Wangtoo Power Plant etc.

As such GoHP, although not a Grid Connected entity, is selling its Royalty Power at the periphery of the generator as a trader client through M/s PTC India Ltd.

ANNEXURE- IA

एनटीपीसी विद्युत व्यापार निगम लिमिटेड
(एनटीपीसी की पूर्ण स्वामित्व वाली सहायक कंपनी)

NTPC Vidyut Vyapar Nigam Limited
(A wholly owned subsidiary of NTPC)

केन्द्रीय कार्यालय/ Corporate Centre

Ref. No.: 01/NVVN/PX/IEX/201702-01 Date: 10-02-2017

To,

India Energy Exchange Limited
Fourth Floor, TDI Centre,
Plot No. 7, Jasola
New Delhi – 110025

Attn.: Mr. Prasanna Rao, Vice President (Market Operations)

Subject: Increase in Block Bid Size

Dear Sir/Madam,

Some of our generator clients wish to place single block bid for 200 MW but are unable to do so as the block bid size allowed presently is 50 MW.

You are requested to increase the block bid size accordingly.

Thanking You,
Yours Faithfully

(ANIL BAWEJA)
AGM (PX & IT)

सातवीं तल, कोर–3, स्कोप कॉम्प्लेक्स, 7, इन्स्टीट्यूशनल एरिया, लोधी रोड, नई दिल्ली–110 003.
कॉर्पोरेट पहचान नम्बर: U40108DL2002GOI117584 टेलीफोन नं: 011-24369565, 24368286 फैक्स नं: 011-24367021, 24362009 ईमेल: contact@nvvn.co.in वेबसाइट: www.nvvn.co.in
7th Floor, Core-3, SCOPE Complex, 7, Institutional Area, Lodi Road, New Delhi–110 003.
Corporate Identification Number: U40108DL2002GOI117584 Tel. No.: 011-24369565, 24368286 Fax No.: 011-24367021, 24362009 email-id: contact@nvvn.co.in Website: www.nvvn.co.in

पंजीकृत कार्यालय: एन टी पी सी भवन, कोर–7, स्कोप कॉम्प्लेक्स, 7, इन्स्टीट्यूशनल एरिया, लोधी रोड, नई दिल्ली–110 003
Regd. Office: NTPC Bhawan, Core-7, SCOPE Complex, 7, Institutional Area, Lodi Road, New Delhi – 110 003

ANNEXURE-IB.

USER ACCEPTANCE TEST SUMMARY REPORT

< Increase in Maximum Quantity per Block Bid in PowerARMS™ DAM segment from 50 to 100 MW>

Document Control

Document Name	UAT Summary Report- Increase in Maximum Quantity per Block Bid in PowerARMS™ DAM segment from 50 to 100 MW
System Version No.	3.7.6.1

	Particulars
Test Performed By	Sudhir Bharti, AVP (MO)
Test Start Date	20th March 2017
Reviewed By	VP (MO)
Approved By	Director(MO)

Classification	Internal Use

TABLE OF CONTENTS

1 INTRODUCTION

1.1 PURPOSE

This Test Report provides a summary of the results of test performed by the Surveillance Team.

2 TEST SUMMARY

The testing is performed to evaluate the performance of Power Arms Front Office system while changing the Block Bid Size from 50 to 100 MW as users of the system and for Operational Acceptance Testing.

2.1 TEST CASE 1: - The testing is performed for live delivery date 25th February 2017 with following activities-

All Single and Block Bids of Live Date 25th February are imported in the Test System and following 8 bids of 50 MW is modified as below:-

Portfolio ID	Portfolio Name	From Period	To Period	Buy/Sell	Bid Price	Earlier BID Quantity (MW)	New Bid Quantity (MW)
S1TH0TPI0001	Thermal Powertech Corporation India Ltd.	0:00	7:00	Sell	2800	-50	-100
S1TH0TPI0001	Thermal Powertech Corporation India Ltd.	0:00	7:00	Sell	2800	-50	
W2MH0RIF0001	Reliance Infrastructure Limited	8:45	23:00	Buy	5500	50	100
W2MH0RIF0001	Reliance Infrastructure Limited	8:45	23:00	Buy	5500	50	
W1MP0MPT0001	MPPTC	0:00	6:00	Buy	1440	50	100
W1MP0MPT0001	MPPTC	0:00	6:00	Buy	1440	50	
W3RK0PTC0522	R K M Powergen Pvt Ltd	0:00	24:00	Sell	1740	-50	-100
W3RK0PTC0522	R K M Powergen Pvt Ltd	0:00	24:00	Sell	1740	-50	

Hence eight numbers of 50 MW Block Bid is changed in 4 numbers of 100 MW Block Bid. Prices, Duration etc. are not changed.

i) Provisional Result: - With Unconstrained Capacity, following are results:-

a) Production Live, 8 No. of 50 MW Block Bids-

System Average Price=2506.13, System Total Volume = 107.06 MUs,

Results of 8 Block Bids:-

Portfolio Code	From Period	To Period	Buy/Sell	Bid Price	BID Quantity (MW)	System Average Price	Matching Status
S1THOTPI0001	0:00	7:00	Sell	2800	-50	1994.56	Excluded
S1THOTPI0001	0:00	7:00	Sell	2800	-50	1994.56	Excluded
W2MHORIF0001	8:45	23:00	Buy	5500	50	2715.51	Included
W2MHORIF0001	8:45	23:00	Buy	5500	50	2715.51	Included
W1MPOMPT0001	0:00	6:00	Buy	1440	50	1951.2	Excluded
W1MPOMPT0001	0:00	6:00	Buy	1440	50	1951.2	Excluded
W3RKOPTC0522	0:00	0:00	Sell	1740	-50	2506.13	Included
W3RKOPTC0522	0:00	0:00	Sell	1740	-50	2506.13	Included

b) Test Environment, 4 No. of 100 MW Block Bids-

System Average Price=2506.13, System Total Volume = 107.06 MUs, Results of 4 Block Bids:-

Portfolio Code	From Period	To Period	Buy/Sell	Bid Price	BID Quantity (MW)	System Average Price	Matching Status
S1THOTPI0001	0:00	7:00	Sell	2800	-100	1994.56	Excluded
W2MHORIF0001	8:45	23:00	Buy	5500	100	2715.51	Included
W1MPOMPT0001	0:00	6:00	Buy	1440	100	1951.2	Excluded
W3RKOPTC0522	0:00	0:00	Sell	1740	-100	2506.13	Included

So, during Provisional Calculation, No Change in Price, Volume and Block Bid Results.

ii) Final Result:- Capacity available under NLDC Exception report is imported in the System, following are the results:-

a) Production Live, With 8 No. of 50 MW Block Bids- NR Import congestion in 61 blocks and SR Import congestion in 76 blocks

Rest of India Price-2317.66; NR Average Price-3002.13; SR Average Price-3308.11

Results of 8 Block Bids:-

Portfolio Code	From Period	To Period	Buy/Sell	Bid Price	BID Quantity (MW)	System Average Price	Matching Status
S1THOTPI0001	0:00	7:00	Sell	2800	-50	2269.52	Excluded
S1THOTPI0001	0:00	7:00	Sell	2800	-50	2269.52	Excluded
W2MHORIF0001	8:45	23:00	Buy	5500	50	2460.6	Included
W2MHORIF0001	8:45	23:00	Buy	5500	50	2460.6	Included
W1MPOMPT0001	0:00	6:00	Buy	1440	50	1947.49	Excluded
W1MPOMPT0001	0:00	6:00	Buy	1440	50	1947.49	Excluded
W3RKOPTC0522	0:00	0:00	Sell	1740	-50	2317.66	Included
W3RKOPTC0522	0:00	0:00	Sell	1740	-50	2317.66	Included

b) Test Environment, 4 No. of 100 MW Block Bids- NR Import congestion in 61 blocks and SR Import congestion in 76 blocks,

Rest of India Price-2317.21; NR Average Price-2999.97; SR Average Price-3308.2; Results of 4 Block Bids:-

Portfolio Code	From Period	To Period	Buy/Sell	Bid Price	BID Quantity (MW)	System Average Price	Matching Status
S1THOTPI0001	0:00	7:00	Sell	2800	-100	2269.85	Excluded
W2MHORIF0001	8:45	23:00	Buy	5500	100	2460.78	Included
W1MPOMPT0001	0:00	6:00	Buy	1440	100	1944.56	Excluded
W3RKOPTC0522	0:00	0:00	Sell	1740	-100	2317.21	Included

Status of Block Bids has not changed in both the cases, Status of Congestion in NR and SR not changed, no significant price change observed.

Output Summary: - In case if the Block Bids are not at margin of the demand-supply curve i.e. there is a significant price difference between Bid Price and System Average Price; then increase in the size of block bid from 50 to 100 MW will make negligible changes in the output in terms of Price and Volume.

. **Test Case 2: - The testing is performed on Live Delivery Date 29th January 2017 with following activities:-**

All Single and Block Bids are imported in the Test System and following 12 bids of 50 MW is modified as below:-

Portfolio ID	Portfolio Name	From Period	To Period	Buy/Sell	Bid Price	Earlier BID Quantity (MW)	New Bid Quantity (MW)
N3PB0PTC0003	Punjab State Power Corporation Ltd	17:00	22:00	Sell	3080	-50	-100
N3PB0PTC0003	Punjab State Power Corporation Ltd	17:00	22:00	Sell	3080	-50	
N3PB0PTC0003	Punjab State Power Corporation Ltd	17:00	22:00	Sell	3080	-50	-100
N3PB0PTC0003	Punjab State Power Corporation Ltd	17:00	22:00	Sell	3080	-50	
W2MH0MSE0001	MSEDCL	08:00	17:00	Buy	3000	50	100
W2MH0MSE0001	MSEDCL	08:00	17:00	Buy	3000	50	
W2MH0MSE0001	MSEDCL	07:30	16:30	Buy	3000	50	100
W2MH0MSE0001	MSEDCL	07:30	16:30	Buy	3000	50	
W3KR0ADN0021	KORBA_WEST_POWER_COMPANY_LTD	08:00	18:00	Sell	2200	-50	-100
W3KR0ADN0021	KORBA_WEST_POWER_COMPANY_LTD	08:00	18:00	Sell	2200	-50	
W2MH0TPC0001	TPCL	00:00	24:00	Buy	2809	50	100
W2MH0TPC0001	TPCL	00:00	24:00	Buy	2809	50	

Hence twelve numbers of 50 MW Block Bid is changed in six numbers of 100 MW Block Bid. Price, Duration etc. are not changed.

i) Provisional Result: - With Unconstrained Capacity, following are results:-

a) Production Live, 12 No. of 50 MW Block Bids-

System Average Price=2332.34, System Total Volume = 96.875 MUs,

Results of 12 Block Bids:-

Portfolio Code	From Period	To Period	Buy/Sell	Bid Price	BID Quantity (MW)	System Average Price	Matching Status
N3PB0PTC0003	17:00	22:00	Sell	3080	-50	2528.15	Excluded
N3PB0PTC0003	17:00	22:00	Sell	3080	-50	2528.15	Excluded
N3PB0PTC0003	17:00	22:00	Sell	3080	-50	2528.15	Excluded
N3PB0PTC0003	17:00	22:00	Sell	3080	-50	2528.15	Excluded
W2MH0MSE0001	8:00	17:00	Buy	3000	50	2547.35	Included
W2MH0MSE0001	8:00	17:00	Buy	3000	50	2547.35	Included
W2MH0MSE0001	7:30	16:30	Buy	3000	50	2564.79	Included
W2MH0MSE0001	7:30	16:30	Buy	3000	50	2564.79	Included
W3KR0ADN0021	8:00	18:00	Sell	2200	-50	2529.6	Included
W3KR0ADN0021	8:00	18:00	Sell	2200	-50	2529.6	Included
W2MH0TPC0001	0:00	24:00:00	Buy	2809	50	2332.34	Included
W2MH0TPC0001	0:00	24:00:00	Buy	2809	50	2332.34	Included

b) Test Environment, 6 No. of 100 MW Block Bids-

System Average Price=2332.34, System Total Volume = 96.875 MUs,

Results of 6 Block Bids:-

Portfolio Code	From Period	To Period	Buy/Sell	Bid Price	BID Quantity (MW)	System Average Price	Matching Status
N3PB0PTC0003	17:00	22:00	Sell	3080	-100	2528.15	Excluded
N3PB0PTC0003	17:00	22:00	Sell	3080	-100	2528.15	Excluded
W2MH0MSE0001	8:00	17:00	Buy	3000	100	2547.35	Included
W2MH0MSE0001	7:30	16:30	Buy	3000	100	2564.79	Included
W3KR0ADN0021	8:00	18:00	Sell	2200	-100	2529.6	Included
W2MH0TPC0001	0:00	24:00:00	Buy	2809	100	2332.34	Included

No Change in Price, Volume and Block Bid Results.

ii) Final Result:- Capacity available under NLDC Exception report is imported in the System, following are the results:-

a) Production Live, With 12 No. of 50 MW Block Bids- NR Import congestion in 46 blocks and SR Import congestion in 55 blocks,

Rest of India Price-2261.30; NR Average Price-2607.70; SR Average Price-2608.21

Results of 12 Block Bids:-

Portfolio Code	From Period	To Period	Buy/Sell	Bid Price	BID Quantity (MW)	System Average Price	Matching Status
N3PB0PTC0003	**17:00**	**22:00**	**Sell**	**3080**	**-50**	**3136.93**	**Included**
N3PB0PTC0003	**17:00**	**22:00**	**Sell**	**3080**	**-50**	**3136.93**	**Included**
N3PB0PTC0003	**17:00**	**22:00**	**Sell**	**3080**	**-50**	**3136.93**	**Paradoxically Rejected**
N3PB0PTC0003	**17:00**	**22:00**	**Sell**	**3080**	**-50**	**3136.93**	**Paradoxically Rejected**
W2MH0MSE0001	8:00	17:00	Buy	3000	50	2544.26	Included
W2MH0MSE0001	8:00	17:00	Buy	3000	50	2544.26	Included
W2MH0MSE0001	7:30	16:30	Buy	3000	50	2557.6	Included
W2MH0MSE0001	7:30	16:30	Buy	3000	50	2557.6	Included
W3KR0ADN0021	8:00	18:00	Sell	2200	-50	2523.67	Included
W3KR0ADN0021	8:00	18:00	Sell	2200	-50	2523.67	Included
W2MH0TPC0001	0:00	24:00:00	Buy	2809	50	2261.3	Included
W2MH0TPC0001	0:00	24:00:00	Buy	2809	50	2261.3	Included

b) Test Environment, 6 No. of 100 MW Block Bids- NR Import congestion in 46 blocks and SR Import congestion in 55 blocks,

Rest of India Price-2262.35; NR Average Price-2630.54; SR Average Price-2608.21;

Results of 6 Block Bids:-

Portfolio Code	From Period	To Period	Buy/Sell	Bid Price	BID Quantity (MW)	System Average Price	Matching Status
N3PB0PTC0003	**17:00**	**22:00**	**Sell**	**3080**	**-100**	**3246.57**	**Paradoxically Rejected**
N3PB0PTC0003	**17:00**	**22:00**	**Sell**	**3080**	**-100**	**3246.57**	**Paradoxically Rejected**
W2MH0MSE0001	8:00	17:00	Buy	3000	100	2544.26	Included

W2MH0MSE0001	7:30	16:30	Buy	3000	100	2557.59	Included
W3KR0ADN0021	8:00	18:00	Sell	2200	-100	2526.17	Included
W2MH0TPC0001	0:00	24:00:00	Buy	2809	100	2262.32	Included

Status of Block Bid of N3PB0PTC0003 has changed since at Margin.

Output Summary: - During Provisional Solution since the Block Bids were not at margin i.e. there were significant price difference between Bid price and System Average Price hence changing the size of block bid from 50 to 100 MW has not made any changes in system price and results.
In Final Solution due to congestion and hence market split the Block Bid of N3PB0PTC0003 became marginal block bid and due to increased size of Block Bid both the block bids of 100 MW got rejected.
While if the block bid were for 50 MW then two block bids were included and two block bids were paradoxically rejected. Hence Block Bid Rejection occurred due to increase in Block Bid Size increased.

Test Case 3: - In this test, quantities of several block bids are changed to 100 MW and then performance of the system is checked. The testing is performed on Live Delivery Date 16th March 2017 with following activities:-

i) All Single and Block Bids are imported in the Test System and certain block bids with quantity 40 to 50 MW is modified to 30 bids of 100 MW.

ii) Provisional Result: - With Unconstrained Capacity, following are results:-

a) Production Live-
System Average Price=2494.28, System Total Volume =115.13 MUs,

b) Test Environment, 30 Number of Block Bids-
System Average Price=2499.61, System Total Volume = 114.73 MUs,

iii) Final Result:- Capacity available under NLDC Exception report is imported in the System, following are the results:-

a) Production Live- NR Import congestion in 65 blocks and SR Import congestion in 76 blocks,
Rest of India Price-2299.48; NR Average Price-2676.15; SR Average Price-3285.09

b) Test Environment, 30 No. of 100 MW Block Bids- NR Import congestion in 65 blocks and SR Import congestion in 76 blocks,
Rest of India Price-2293.39; NR Average Price-2678.67; SR Average Price-3278.93;

Output Summary: - While changing the Block Bid size of 40 MW & 50 MW to 100 MW it is observed that no significant change has occurred in Price during Provisional and Final Price Results. Also the Performance of System was also similar (like time taken by the System to perform the Price Calculation).

3 SUGGESTED ACTIONS

The Test is performed for 3 Production Live Dates wherein certain block bids were changed to 100 MW and it is observed that no significant changes were detected in following parameters:-

I) Performance of System

II) Market Clearing Price and Volume

III) Area Clearing Price and Volume

IV) No. of Blocks of Market Split

Hence it is suggested that we can go-ahead with the parameter change i.e. from 50 MW to 100 MW.

Appendix A: Test Summary Report Approval

The undersigned acknowledge they have reviewed the **Test Summary Report** and agree with the approach it is presented

Signature: Date: 7/4/17

Name: SUDHIR BHARTI

Signature: Date: 8/4/17

Name: PRASANNA RAO

Signature: Date: 10/4/17.

Name: Akhilesh Awasthy

NETWORK PATH WHERE DOCUMENT IS LOCATED: -

1) For Test Case1:- 172.16.29.221/M:\Powerarms Testing\Testing_50-100MW\Final\120170225_D

2) For Test case 2:- 172.16.29.221/M:\Powerarms Testing\Testing_50-100MW\Final\220170129

3) For Test case 3:- 172.16.29.221/M:\Powerarms Testing\Testing_50-100MW\Final\15032017_OK

Annexure-IC

Delivery Date	Total no. of Portfolios	No. of Portfolios with Single Bids	No. of Portfolio with Block Bids	No. of Portfolios with Blocks Bids Qty. >50 MW	% Portfolios with Block Bids Q>50 MW to total no. of Portfolios
13-Apr-17	1127	461	704	1	0.09%
14-Apr-17	1118	456	697	3	0.27%
15-Apr-17	1129	451	708	4	0.35%
16-Apr-17	1061	420	667	3	0.28%
17-Apr-17	1092	456	665	3	0.27%
18-Apr-17	1145	470	707	4	0.35%
19-Apr-17	1147	471	712	4	0.35%
20-Apr-17	1145	479	699	3	0.26%
21-Apr-17	1136	480	690	3	0.26%
22-Apr-17	1144	477	704	4	0.35%
23-Apr-17	1072	443	664	3	0.28%
24-Apr-17	1101	470	668	3	0.27%
25-Apr-17	1166	488	714	4	0.34%
26-Apr-17	1173	491	717	4	0.34%
27-Apr-17	1178	489	725	4	0.34%
28-Apr-17	1139	472	703	6	0.53%
29-Apr-17	1138	474	700	4	0.35%
30-Apr-17	1058	437	649	2	0.19%
1-May-17	835	328	529	1	0.12%
2-May-17	923	371	580	3	0.33%
3-May-17	1042	443	626	2	0.19%
4-May-17	1042	441	627	2	0.19%
5-May-17	973	428	572	7	0.72%
6-May-17	1004	441	592	6	0.60%
7-May-17	941	399	571	6	0.64%
8-May-17	975	428	579	5	0.51%
9-May-17	970	425	572	6	0.62%
10-May-17	1020	434	615	7	0.69%
11-May-17	1082	449	661	6	0.55%
12-May-17	1090	458	663	8	0.73%
13-May-17	1045	440	633	7	0.67%
14-May-17	989	421	597	7	0.71%
15-May-17	1016	443	606	7	0.69%
16-May-17	999	438	595	9	0.90%
17-May-17	1035	452	613	8	0.77%
18-May-17	1054	452	633	9	0.85%
19-May-17	1041	461	610	9	0.86%
20-May-17	1056	467	616	8	0.76%
21-May-17	998	435	590	7	0.70%
22-May-17	1021	446	603	5	0.49%
23-May-17	1027	451	602	5	0.49%
24-May-17	1043	462	609	6	0.58%
25-May-17	1038	455	612	4	0.39%
26-May-17	1011	450	591	5	0.49%
27-May-17	989	442	576	5	0.51%
28-May-17	971	420	581	6	0.62%

Delivery Date	Total no. of Portfolios	No. of Portfolios with Single Bids	No. of Portfolio with Block Bids	No. of Portfolios with Blocks Bids Qty. >50 MW	% Portfolios with Block Bids Q>50 MW to total no. of Portfolios
29-May-17	999	445	584	7	0.70%
30-May-17	1025	452	604	8	0.78%
31-May-17	1056	461	628	5	0.47%
1-Jun-17	915	410	532	6	0.66%
2-Jun-17	1011	458	584	9	0.89%
3-Jun-17	1043	464	612	10	0.96%
4-Jun-17	987	423	597	10	1.01%
5-Jun-17	1000	443	593	11	1.10%
6-Jun-17	982	446	569	8	0.81%
7-Jun-17	969	448	554	8	0.83%
8-Jun-17	1048	463	617	8	0.76%
9-Jun-17	1051	463	620	9	0.86%
10-Jun-17	1048	455	626	10	0.95%
11-Jun-17	987	421	599	11	1.11%
12-Jun-17	1005	441	602	10	1.00%
13-Jun-17	1036	458	614	13	1.25%
14-Jun-17	1060	470	623	11	1.04%
15-Jun-17	1063	472	627	8	0.75%
16-Jun-17	1047	466	615	11	1.05%
17-Jun-17	983	447	568	8	0.81%
18-Jun-17	947	419	560	7	0.74%
19-Jun-17	1010	455	591	9	0.89%
20-Jun-17	1038	469	606	11	1.06%
21-Jun-17	1040	474	600	9	0.87%
22-Jun-17	1060	473	622	12	1.13%
23-Jun-17	1050	471	616	11	1.05%
24-Jun-17	1062	464	637	13	1.22%
25-Jun-17	986	415	605	13	1.32%
26-Jun-17	999	440	595	10	1.00%
27-Jun-17	1033	460	609	12	1.16%
28-Jun-17	1036	466	603	10	0.97%
29-Jun-17	1028	456	601	8	0.78%
30-Jun-17	1023	453	604	9	0.88%
Average	**1040**	**449**	**622**	**7**	**0.67%**

Annexure-ID

Delivery Date	Total no. of Bids	No. of Single Bids	No. of Block Bids	Blocks Bids with Bid Qty. >50 MW	% Block Bids with Q>50 MW to total no. of block bids
13-Apr-17	4425	461	3964	5	0.13%
14-Apr-17	4301	456	3845	16	0.42%
15-Apr-17	4102	451	3651	10	0.27%
16-Apr-17	3900	420	3480	7	0.20%
17-Apr-17	4165	456	3709	8	0.22%
18-Apr-17	4413	470	3943	12	0.30%
19-Apr-17	4433	471	3962	12	0.30%
20-Apr-17	4265	479	3786	9	0.24%
21-Apr-17	4316	480	3836	9	0.23%
22-Apr-17	4351	477	3874	10	0.26%
23-Apr-17	3978	443	3535	12	0.34%
24-Apr-17	4328	470	3858	9	0.23%
25-Apr-17	4590	488	4102	9	0.22%
26-Apr-17	4613	491	4122	42	1.02%
27-Apr-17	4497	489	4008	38	0.95%
28-Apr-17	4453	472	3981	46	1.16%
29-Apr-17	4220	474	3746	33	0.88%
30-Apr-17	3879	437	3442	13	0.38%
1-May-17	3186	328	2858	1	0.03%
2-May-17	3751	371	3380	17	0.50%
3-May-17	4196	443	3753	10	0.27%
4-May-17	4095	441	3654	11	0.30%
5-May-17	4074	428	3646	27	0.74%
6-May-17	4248	441	3807	36	0.95%
7-May-17	3968	399	3569	59	1.65%
8-May-17	4131	428	3703	41	1.11%
9-May-17	4167	425	3742	39	1.04%
10-May-17	4340	434	3906	67	1.72%
11-May-17	4472	449	4023	52	1.29%
12-May-17	4437	458	3979	75	1.88%
13-May-17	4320	440	3880	44	1.13%
14-May-17	3916	421	3495	50	1.43%
15-May-17	4082	443	3639	78	2.14%
16-May-17	4414	438	3976	63	1.58%
17-May-17	4415	452	3963	42	1.06%
18-May-17	4485	452	4033	64	1.59%
19-May-17	4358	461	3897	71	1.82%
20-May-17	4280	467	3813	74	1.94%
21-May-17	4105	435	3670	72	1.96%
22-May-17	4219	446	3773	55	1.46%
23-May-17	4391	451	3940	70	1.78%
24-May-17	4360	462	3898	62	1.59%

Delivery Date	Total no. of Bids	No. of Single Bids	No. of Block Bids	Blocks Bids with Bid Qty. >50 MW	% Block Bids with Q>50 MW to total no. of block bids
25-May-17	4412	455	3957	42	1.06%
26-May-17	4399	450	3949	41	1.04%
27-May-17	4361	442	3919	43	1.10%
28-May-17	4127	420	3707	53	1.43%
29-May-17	4253	445	3808	58	1.52%
30-May-17	4292	452	3840	65	1.69%
31-May-17	4427	461	3966	53	1.34%
1-Jun-17	3883	410	3473	33	0.95%
2-Jun-17	4312	458	3854	90	2.34%
3-Jun-17	4452	464	3988	67	1.68%
4-Jun-17	4140	423	3717	86	2.31%
5-Jun-17	4289	443	3846	77	2.00%
6-Jun-17	4351	446	3905	69	1.77%
7-Jun-17	4315	448	3867	99	2.56%
8-Jun-17	4493	463	4030	137	3.40%
9-Jun-17	4546	463	4083	126	3.09%
10-Jun-17	4453	455	3998	134	3.35%
11-Jun-17	4192	421	3771	145	3.85%
12-Jun-17	4349	441	3908	145	3.71%
13-Jun-17	4579	458	4121	153	3.71%
14-Jun-17	4564	470	4094	157	3.83%
15-Jun-17	4553	472	4081	126	3.09%
16-Jun-17	4534	466	4068	131	3.22%
17-Jun-17	4413	447	3966	138	3.48%
18-Jun-17	4083	419	3664	116	3.17%
19-Jun-17	4293	455	3838	137	3.57%
20-Jun-17	4436	469	3967	138	3.48%
21-Jun-17	4431	474	3957	156	3.94%
22-Jun-17	4467	473	3994	196	4.91%
23-Jun-17	4402	471	3931	148	3.76%
24-Jun-17	4330	464	3866	136	3.52%
25-Jun-17	3936	415	3521	144	4.09%
26-Jun-17	4180	440	3740	79	2.11%
27-Jun-17	4299	460	3839	117	3.05%
28-Jun-17	4203	466	3737	101	2.70%
29-Jun-17	4162	456	3706	81	2.19%
30-Jun-17	4123	453	3670	70	1.91%
Average	**4274**	**449**	**3825**	**68**	**1.75%**

Annexure-IE

Delivery Date	Total No. of Block Bids>50 MW	No. of Block Bids>50 MW selected in Provisional result	No. of Block Bids >50 MW Selected in Final result	No. of Block Bids>50 MW rejected in Provisional result	No. of Block Bids>50 MW rejected in Final result	Block Bids selected in Prov. but not in final	Block Bids selected in Final but not in Provisional
13-Apr-17	5	5	5	0	0	**0**	**0**
14-Apr-17	16	10	10	6	6	**0**	**0**
15-Apr-17	10	8	8	2	2	**0**	**0**
16-Apr-17	7	6	6	1	1	**0**	**0**
17-Apr-17	8	8	8	0	0	**0**	**0**
18-Apr-17	12	10	10	2	2	**0**	**0**
19-Apr-17	12	10	10	2	2	**0**	**0**
20-Apr-17	9	9	9	0	0	**0**	**0**
21-Apr-17	9	8	7	1	2	**1**	**0**
22-Apr-17	10	9	9	1	1	**0**	**0**
23-Apr-17	12	6	6	6	6	**0**	**0**
24-Apr-17	9	9	9	0	0	**0**	**0**
25-Apr-17	9	6	5	3	4	**1**	**0**
26-Apr-17	42	33	33	9	9	**0**	**0**
27-Apr-17	38	28	30	10	8	**0**	**2**
28-Apr-17	46	24	28	22	18	**0**	**4**
29-Apr-17	33	9	11	24	22	**0**	**2**
30-Apr-17	13	4	4	9	9	**0**	**0**
1-May-17	1	1	1	0	0	**0**	**0**
2-May-17	17	12	12	5	5	**0**	**0**
3-May-17	10	10	10	0	0	**0**	**0**
4-May-17	11	11	11	0	0	**0**	**0**
5-May-17	27	23	23	4	4	**0**	**0**
6-May-17	36	31	31	5	5	**0**	**0**
7-May-17	59	47	47	12	12	**0**	**0**
8-May-17	41	33	32	8	9	**1**	**0**
9-May-17	39	29	29	10	10	**0**	**0**
10-May-17	67	49	49	18	18	**0**	**0**
11-May-17	52	37	37	15	15	**0**	**0**
12-May-17	75	56	56	19	19	**0**	**0**
13-May-17	44	42	42	2	2	**0**	**0**
14-May-17	50	45	45	5	5	**0**	**0**
15-May-17	78	55	55	23	23	**0**	**0**
16-May-17	63	57	57	6	6	**0**	**0**
17-May-17	42	38	38	4	4	**0**	**0**
18-May-17	64	44	44	20	20	**0**	**0**
19-May-17	71	53	53	18	18	**0**	**0**
20-May-17	74	55	55	19	19	**0**	**0**
21-May-17	72	42	36	30	36	**6**	**0**
22-May-17	55	41	41	14	14	**0**	**0**
23-May-17	70	37	37	33	33	**0**	**0**
24-May-17	62	55	55	7	7	**0**	**0**
25-May-17	42	40	40	2	2	**0**	**0**
26-May-17	41	39	39	2	2	**0**	**0**
27-May-17	43	40	40	3	3	**0**	**0**
28-May-17	53	29	29	24	24	**0**	**0**
29-May-17	58	39	39	19	19	**0**	**0**
30-May-17	65	32	31	33	34	**1**	**0**

Delivery Date	Total No. of Block Bids>50 MW	No. of Block Bids>50 MW selected in Provisional result	No. of Block Bids >50 MW Selected in Final result	No. of Block Bids>50 MW rejected in Provisional result	No. of Block Bids>50 MW rejected in Final result	Block Bids selected in Prov. but not in final	Block Bids selected in Final but not in Provisional
31-May-17	53	37	37	16	16	**0**	**0**
1-Jun-17	33	30	30	3	3	**0**	**0**
2-Jun-17	90	40	40	50	50	**0**	**0**
3-Jun-17	67	53	53	14	14	**0**	**0**
4-Jun-17	86	64	64	22	22	**0**	**0**
5-Jun-17	77	65	65	12	12	**0**	**0**
6-Jun-17	69	65	65	4	4	**0**	**0**
7-Jun-17	99	28	28	71	71	**0**	**0**
8-Jun-17	137	47	47	90	90	**0**	**0**
9-Jun-17	126	64	64	62	62	**0**	**0**
10-Jun-17	134	60	60	74	74	**0**	**0**
11-Jun-17	145	38	38	107	107	**0**	**0**
12-Jun-17	145	56	56	89	89	**0**	**0**
13-Jun-17	153	70	70	83	83	**0**	**0**
14-Jun-17	157	74	74	83	83	**0**	**0**
15-Jun-17	126	68	68	58	58	**0**	**0**
16-Jun-17	131	90	90	41	41	**0**	**0**
17-Jun-17	138	68	61	70	77	**7**	**0**
18-Jun-17	116	86	86	30	30	**0**	**0**
19-Jun-17	137	91	91	46	46	**0**	**0**
20-Jun-17	138	93	93	45	45	**0**	**0**
21-Jun-17	156	60	60	96	96	**0**	**0**
22-Jun-17	196	78	78	118	118	**0**	**0**
23-Jun-17	148	66	66	82	82	**0**	**0**
24-Jun-17	136	80	80	56	56	**0**	**0**
25-Jun-17	144	51	51	93	93	**0**	**0**
26-Jun-17	79	49	49	30	30	**0**	**0**
27-Jun-17	117	37	37	80	80	**0**	**0**
28-Jun-17	101	52	46	49	55	**6**	**0**
29-Jun-17	81	41	41	40	40	**0**	**0**
30-Jun-17	70	31	31	39	39	**0**	**0**

Annexure-IIA

Delivery Date	Total No. of Block Bids>50 MW	No. of Block Bids>50 MW selected in Provisional result	No. of Block Bids >50 MW Selected in Final result	No. of Block Bids>50 MW rejected in Provisional result	No. of Block Bids>50 MW rejected in Final result	Block Bids selected in Prov. but not in final	Block Bids selected in Final but not in Provisional	Total time Blocks when MCP<>ACP with No Split
13-Apr-17	5	5	5	0	0	**0**	**0**	**31**
14-Apr-17	16	10	10	6	6	**0**	**0**	**27**
15-Apr-17	10	8	8	2	2	**0**	**0**	**50**
16-Apr-17	7	6	6	1	1	**0**	**0**	**43**
17-Apr-17	8	8	8	0	0	**0**	**0**	**11**
18-Apr-17	12	10	10	2	2	**0**	**0**	**14**
19-Apr-17	12	10	10	2	2	**0**	**0**	**12**
20-Apr-17	9	9	9	0	0	**0**	**0**	**6**
21-Apr-17	9	8	7	1	2	**1**	**0**	**15**
22-Apr-17	10	9	9	1	1	**0**	**0**	**26**
23-Apr-17	12	6	6	6	6	**0**	**0**	**45**
24-Apr-17	9	9	9	0	0	**0**	**0**	**0**
25-Apr-17	9	6	5	3	4	**1**	**0**	**53**
26-Apr-17	42	33	33	9	9	**0**	**0**	**40**
27-Apr-17	38	28	30	10	8	**0**	**2**	**50**
28-Apr-17	46	24	28	22	18	**0**	**4**	**52**
29-Apr-17	33	9	11	24	22	**0**	**2**	**61**
30-Apr-17	13	4	4	9	9	**0**	**0**	**30**
1-May-17	1	1	1	0	0	**0**	**0**	**0**
2-May-17	17	12	12	5	5	**0**	**0**	**0**
3-May-17	10	10	10	0	0	**0**	**0**	**76**
4-May-17	11	11	11	0	0	**0**	**0**	**39**
5-May-17	27	23	23	4	4	**0**	**0**	**26**
6-May-17	36	31	31	5	5	**0**	**0**	**78**
7-May-17	59	47	47	12	12	**0**	**0**	**69**
8-May-17	41	33	32	8	9	**1**	**0**	**7**
9-May-17	39	29	29	10	10	**0**	**0**	**26**
10-May-17	67	49	49	18	18	**0**	**0**	**81**
11-May-17	52	37	37	15	15	**0**	**0**	**0**
12-May-17	75	56	56	19	19	**0**	**0**	**0**
13-May-17	44	42	42	2	2	**0**	**0**	**0**
14-May-17	50	45	45	5	5	**0**	**0**	**70**
15-May-17	78	55	55	23	23	**0**	**0**	**88**
16-May-17	63	57	57	6	6	**0**	**0**	**17**
17-May-17	42	38	38	4	4	**0**	**0**	**44**
18-May-17	64	44	44	20	20	**0**	**0**	**0**
19-May-17	71	53	53	18	18	**0**	**0**	**0**
20-May-17	74	55	55	19	19	**0**	**0**	**0**
21-May-17	72	42	36	30	36	**6**	**0**	**24**
22-May-17	55	41	41	14	14	**0**	**0**	**12**
23-May-17	70	37	37	33	33	**0**	**0**	**0**
24-May-17	62	55	55	7	7	**0**	**0**	**0**
25-May-17	42	40	40	2	2	**0**	**0**	**0**
26-May-17	41	39	39	2	2	**0**	**0**	**0**
27-May-17	43	40	40	3	3	**0**	**0**	**0**
28-May-17	53	29	29	24	24	**0**	**0**	**0**
29-May-17	58	39	39	19	19	**0**	**0**	**0**
30-May-17	65	32	31	33	34	**1**	**0**	**2**
31-May-17	53	37	37	16	16	**0**	**0**	**0**
1-Jun-17	33	30	30	3	3	**0**	**0**	**0**
2-Jun-17	90	40	40	50	50	**0**	**0**	**0**
3-Jun-17	67	53	53	14	14	**0**	**0**	**0**
4-Jun-17	86	64	64	22	22	**0**	**0**	**0**
5-Jun-17	77	65	65	12	12	**0**	**0**	**0**
6-Jun-17	69	65	65	4	4	**0**	**0**	**0**

Delivery Date	Total No. of Block Bids>50 MW	No. of Block Bids>50 MW selected in Provisional result	No. of Block Bids >50 MW Selected in Final result	No. of Block Bids>50 MW rejected in Provisional result	No. of Block Bids>50 MW rejected in Final result	Block Bids selected in Prov. but not in final	Block Bids selected in Final but not in Provisional	Total time Blocks when MCP<>ACP with No Split
7-Jun-17	99	28	28	71	71	0	0	0
8-Jun-17	137	47	47	90	90	0	0	0
9-Jun-17	126	64	64	62	62	0	0	0
10-Jun-17	134	60	60	74	74	0	0	0
11-Jun-17	145	38	38	107	107	0	0	0
12-Jun-17	145	56	56	89	89	0	0	0
13-Jun-17	153	70	70	83	83	0	0	0
14-Jun-17	157	74	74	83	83	0	0	4
15-Jun-17	126	68	68	58	58	0	0	0
16-Jun-17	131	90	90	41	41	0	0	49
17-Jun-17	138	68	61	70	77	7	0	70
18-Jun-17	116	86	86	30	30	0	0	0
19-Jun-17	137	91	91	46	46	0	0	0
20-Jun-17	138	93	93	45	45	0	0	0
21-Jun-17	156	60	60	96	96	0	0	0
22-Jun-17	196	78	78	118	118	0	0	0
23-Jun-17	148	66	66	82	82	0	0	0
24-Jun-17	136	80	80	56	56	0	0	0
25-Jun-17	144	51	51	93	93	0	0	0
26-Jun-17	79	49	49	30	30	0	0	0
27-Jun-17	117	37	37	80	80	0	0	0
28-Jun-17	101	52	46	49	55	6	0	75
29-Jun-17	81	41	41	40	40	0	0	0
30-Jun-17	70	31	31	39	39	0	0	0

Annexure-IIB

Month	Price Diff. <10 paise	Price Diff. 10-20 paise	Price Diff. 20-30 paise	Difference greater than 30 paise	Total Blocks when MCP<>ACP with No Split	No. of Blocks when Exception Received
Jan-17	582	42	25	13	662	1058
Feb-17	896	57	6	5	964	1086
Mar-17	586	9	1	0	596	614
Apr-17	319	27	8	6	360	362
May-17	400	36	10	8	454	469
Jun-17	674	47	10	18	749	1251
Jul-17	816	76	20	6	918	1706
Aug-17	805	75	33	26	939	1469
Sep-17	918	47	12	7	984	1481
Oct-17	672	22	3	1	698	1407
Nov-17	791	40	23	4	858	1011
Dec-17	690	14	18	7	729	1108
Jan-17	858	53	9	3	923	978
Feb-17	531	33	13	4	581	588
Mar-17	872	34	9	3	918	1215
1-12 Apr 17	322	20	1	0	343	657
13-31 Apr 17	515	39	8	4	566	685
May-17	621	30	4	4	659	2584
Jun-17	177	8	2	1	188	108

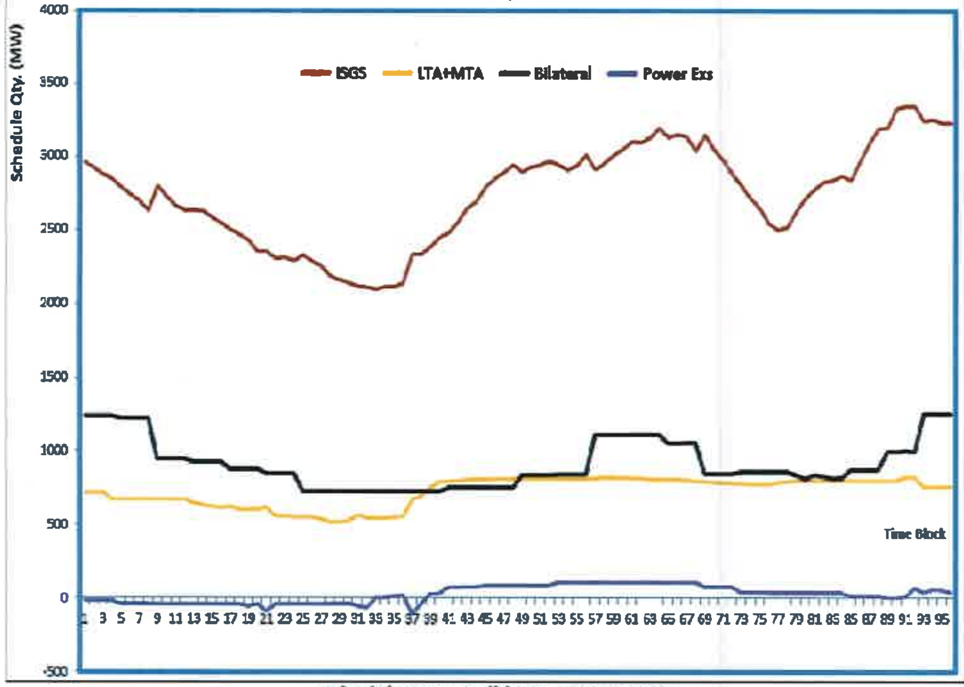
Annexure IIIA

Delivery Date	Total No. of Block Bids>50 MW	No. of Block Bids>50 MW selected in Provisional result	No. of Block Bids >50 MW Selected in Final result	No. of Block Bids>50 MW rejected in Provisional result	No. of Block Bids>50 MW rejected in Final result	Block Bids selected in Prov. but not in final	Block Bids selected in Final but not in Provisional	Sum of ∑ACV-MCV for Blocks where ∑ACV>MCV in MWhr
13-Apr-17	5	5	5	0	0	0	0	662
14-Apr-17	16	10	10	6	6	0	0	495
15-Apr-17	10	8	8	2	2	0	0	1036
16-Apr-17	7	6	6	1	1	0	0	186
17-Apr-17	8	8	8	0	0	0	0	416
18-Apr-17	12	10	10	2	2	0	0	504
19-Apr-17	12	10	10	2	2	0	0	2176
20-Apr-17	9	9	9	0	0	0	0	1139
21-Apr-17	9	8	7	1	2	1	0	789
22-Apr-17	10	9	9	1	1	0	0	2091
23-Apr-17	12	6	6	6	6	0	0	62
24-Apr-17	9	9	9	0	0	0	0	
25-Apr-17	9	6	5	3	4	1	0	21
26-Apr-17	42	33	33	9	9	0	0	743
27-Apr-17	38	28	30	10	8	0	2	2494
28-Apr-17	46	24	28	22	18	0	4	2041
29-Apr-17	33	9	11	24	22	0	2	2342
30-Apr-17	13	4	4	9	9	0	0	1012
1-May-17	1	1	1	0	0	0	0	
2-May-17	17	12	12	5	5	0	0	
3-May-17	10	10	10	0	0	0	0	245
4-May-17	11	11	11	0	0	0	0	744
5-May-17	27	23	23	4	4	0	0	800
6-May-17	36	31	31	5	5	0	0	
7-May-17	59	47	47	12	12	0	0	943
8-May-17	41	33	32	8	9	1	0	9
9-May-17	39	29	29	10	10	0	0	70
10-May-17	67	49	49	18	18	0	0	286
11-May-17	52	37	37	15	15	0	0	
12-May-17	75	56	56	19	19	0	0	
13-May-17	44	42	42	2	2	0	0	
14-May-17	50	45	45	5	5	0	0	807
15-May-17	78	55	55	23	23	0	0	419
16-May-17	63	57	57	6	6	0	0	5
17-May-17	42	38	38	4	4	0	0	340
18-May-17	64	44	44	20	20	0	0	
19-May-17	71	53	53	18	18	0	0	
20-May-17	74	55	55	19	19	0	0	
21-May-17	72	42	36	30	36	6	0	1263
22-May-17	55	41	41	14	14	0	0	2
23-May-17	70	37	37	33	33	0	0	
24-May-17	62	55	55	7	7	0	0	
25-May-17	42	40	40	2	2	0	0	
26-May-17	41	39	39	2	2	0	0	
27-May-17	43	40	40	3	3	0	0	
28-May-17	53	29	29	24	24	0	0	
29-May-17	58	39	39	19	19	0	0	
30-May-17	65	32	31	33	34	1	0	
31-May-17	53	37	37	16	16	0	0	
1-Jun-17	33	30	30	3	3	0	0	
2-Jun-17	90	40	40	50	50	0	0	
3-Jun-17	67	53	53	14	14	0	0	
4-Jun-17	86	64	64	22	22	0	0	
5-Jun-17	77	65	65	12	12	0	0	
6-Jun-17	69	65	65	4	4	0	0	
7-Jun-17	99	28	28	71	71	0	0	
8-Jun-17	137	47	47	90	90	0	0	
9-Jun-17	126	64	64	62	62	0	0	
10-Jun-17	134	60	60	74	74	0	0	
11-Jun-17	145	38	38	107	107	0	0	
12-Jun-17	145	56	56	89	89	0	0	
13-Jun-17	153	70	70	83	83	0	0	
14-Jun-17	157	74	74	83	83	0	0	
15-Jun-17	126	68	68	58	58	0	0	
16-Jun-17	131	90	90	41	41	0	0	
17-Jun-17	138	68	61	70	77	7	0	
18-Jun-17	116	86	86	30	30	0	0	
19-Jun-17	137	91	91	46	46	0	0	

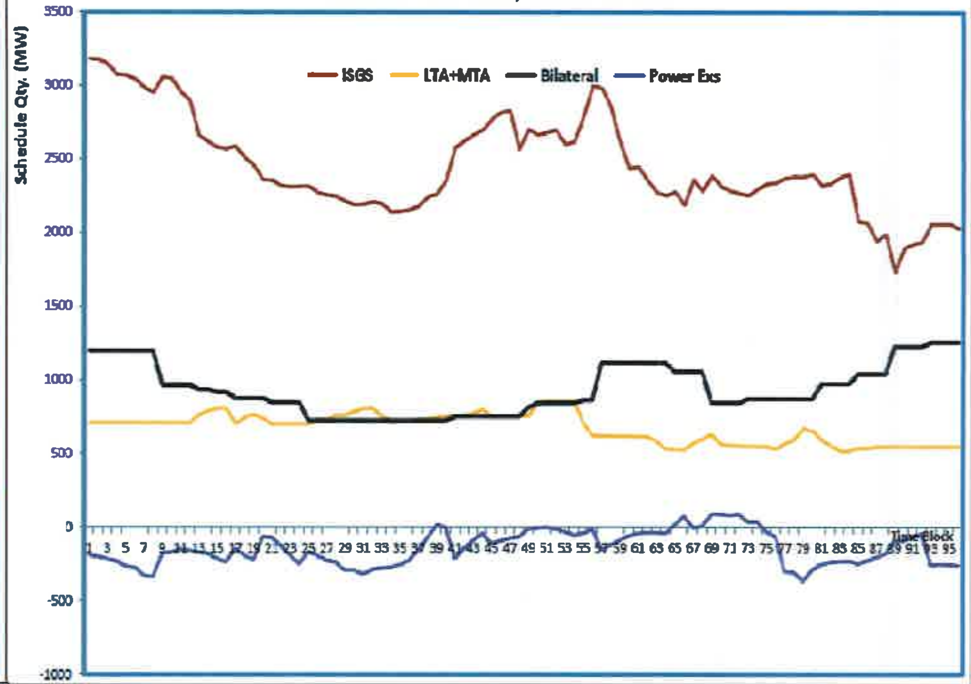
Delivery Date	Total No. of Block Bids>50 MW	No. of Block Bids>50 MW selected in Provisional result	No. of Block Bids >50 MW Selected in Final result	No. of Block Bids>50 MW rejected in Provisional result	No. of Block Bids>50 MW rejected in Final result	Block Bids selected in Prov. but not in final	Block Bids selected in Final but not in Provisional	Sum of ∑ACV-MCV for Blocks where ∑ACV>MCV in MWhr
20-Jun-17	138	93	93	45	45	0	0	
21-Jun-17	156	60	60	96	96	0	0	
22-Jun-17	196	78	78	118	118	0	0	
23-Jun-17	148	66	66	82	82	0	0	
24-Jun-17	136	80	80	56	56	0	0	
25-Jun-17	144	51	51	93	93	0	0	
26-Jun-17	79	49	49	30	30	0	0	
27-Jun-17	117	37	37	80	80	0	0	
28-Jun-17	101	52	46	49	55	6	0	
29-Jun-17	81	41	41	40	40	0	0	
30-Jun-17	70	31	31	39	39	0	0	

ANNEXURE- IV A.

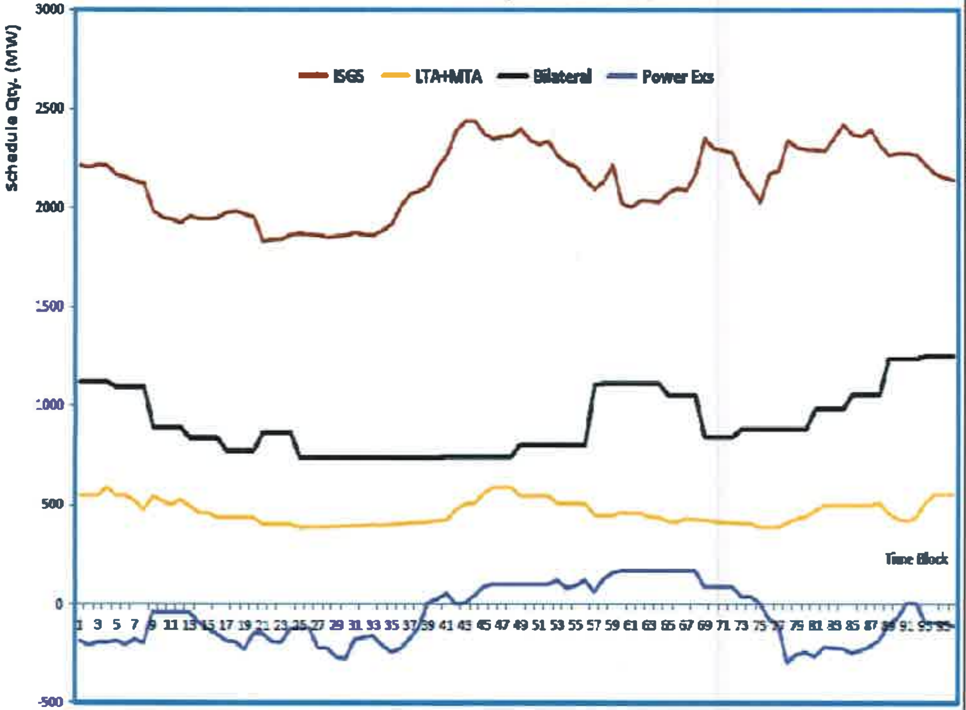
Schedule State-Delhi, Date-27-06-2017



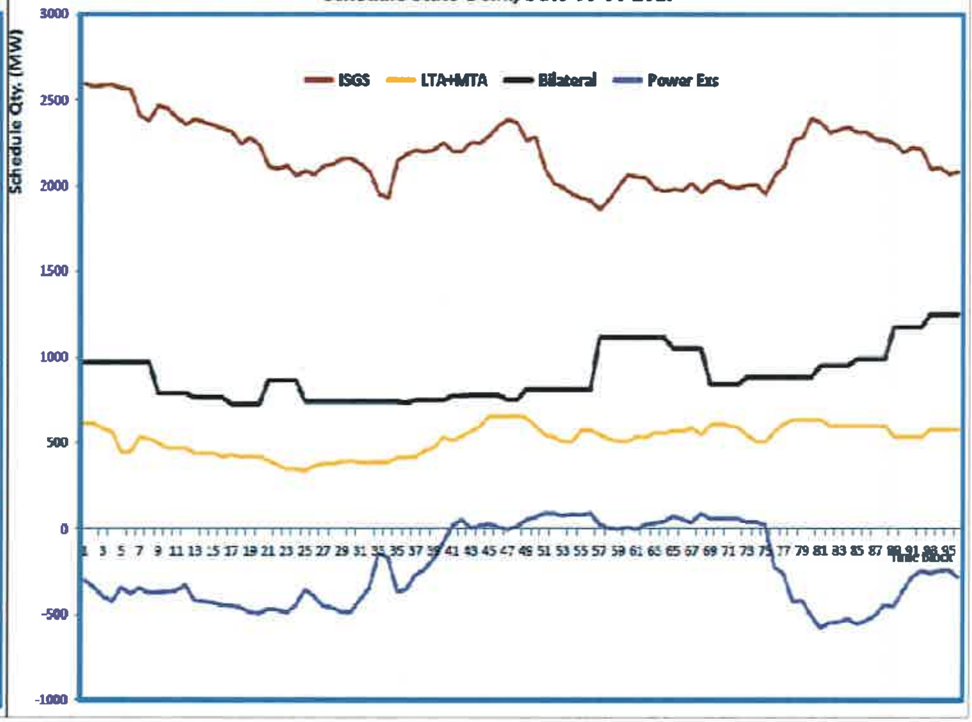
Schedule State-Delhi, Date-28-06-2017



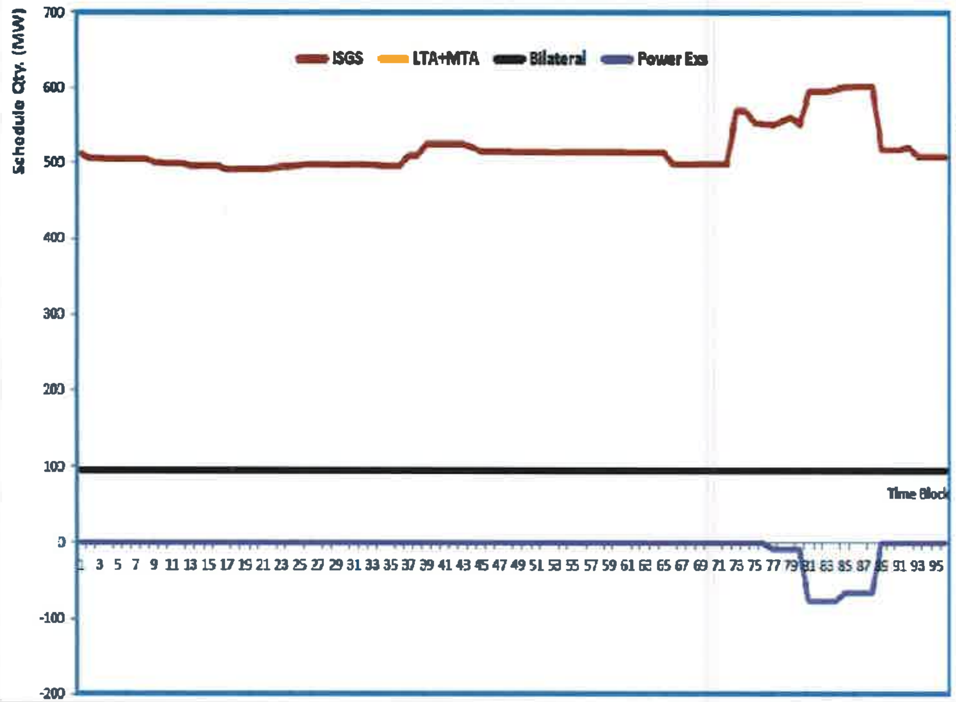
Schedule State-Delhi, Date-29-06-2017



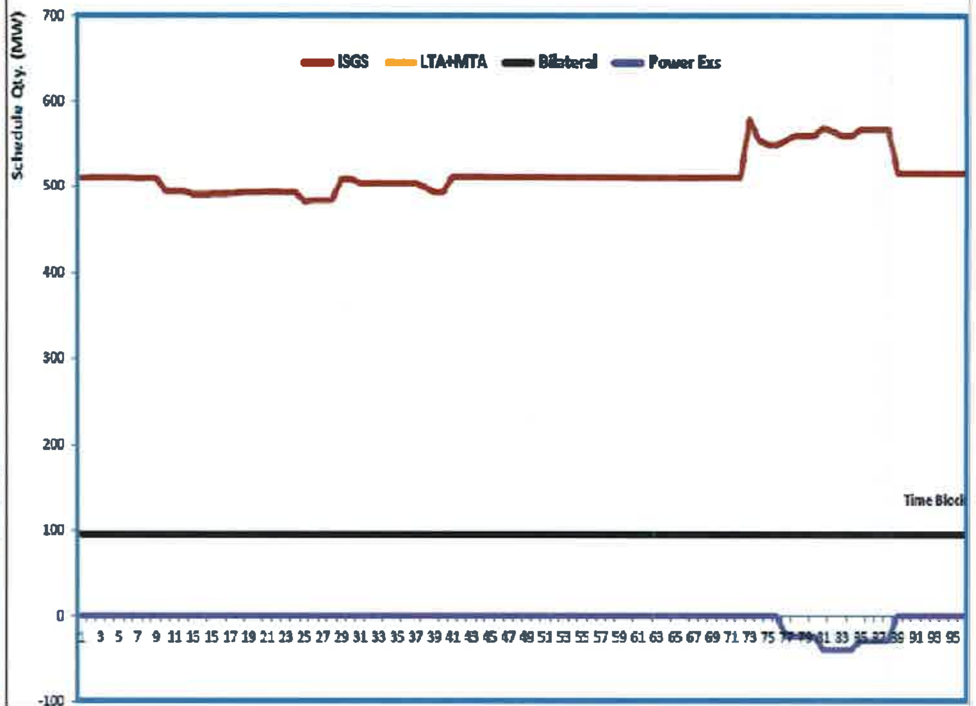
Schedule State-Delhi, Date-30-06-2017



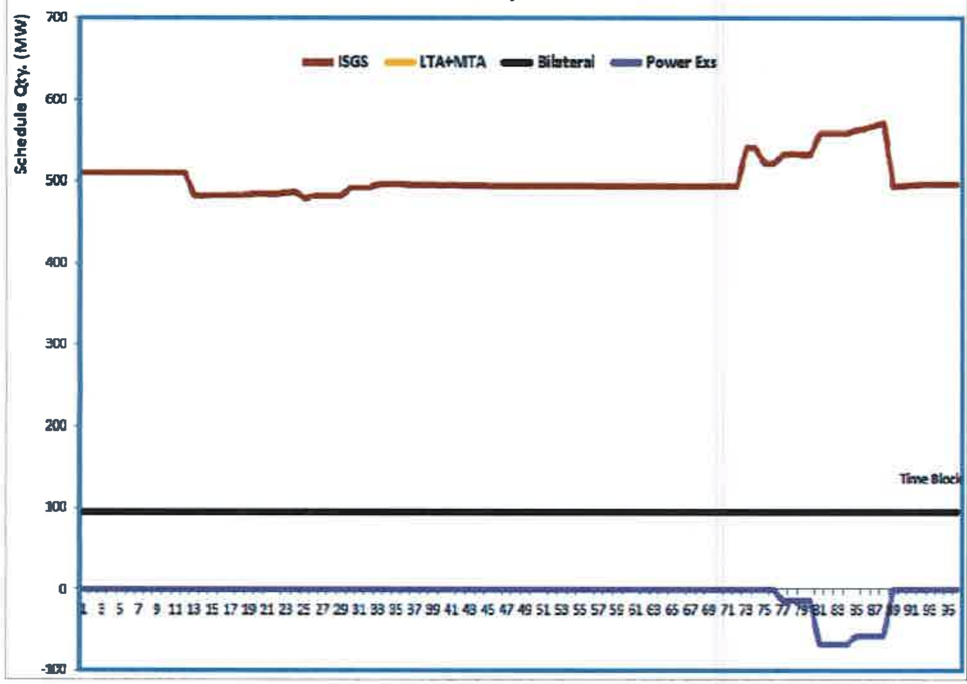
Schedule State-DNH, Date-27-06-2017



Schedule State-DNH, Date-28-06-2017



Schedule State-DNH, Date-29-06-2017



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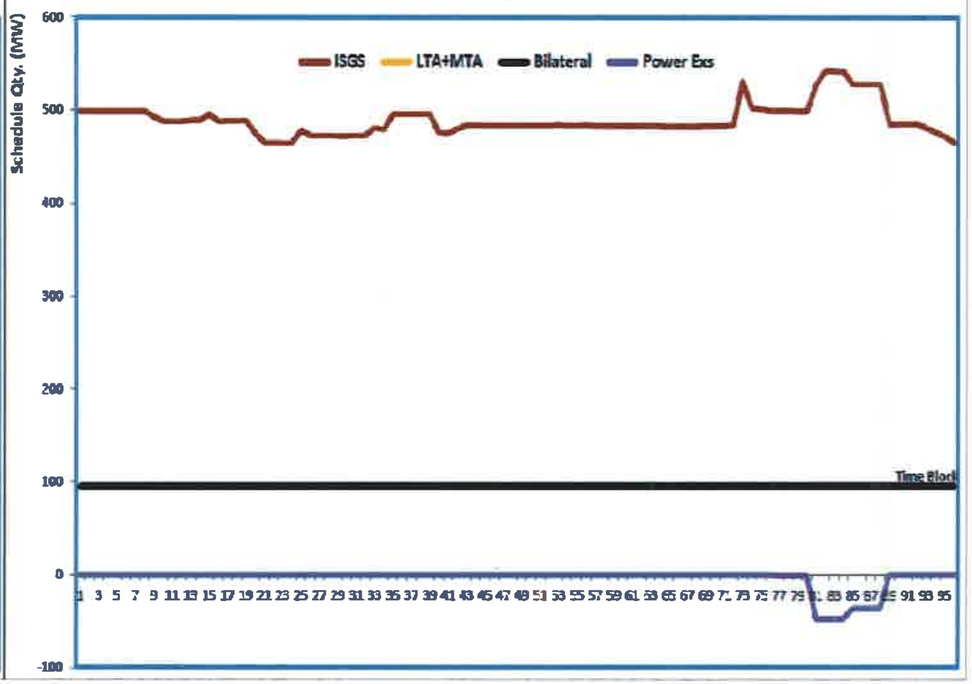

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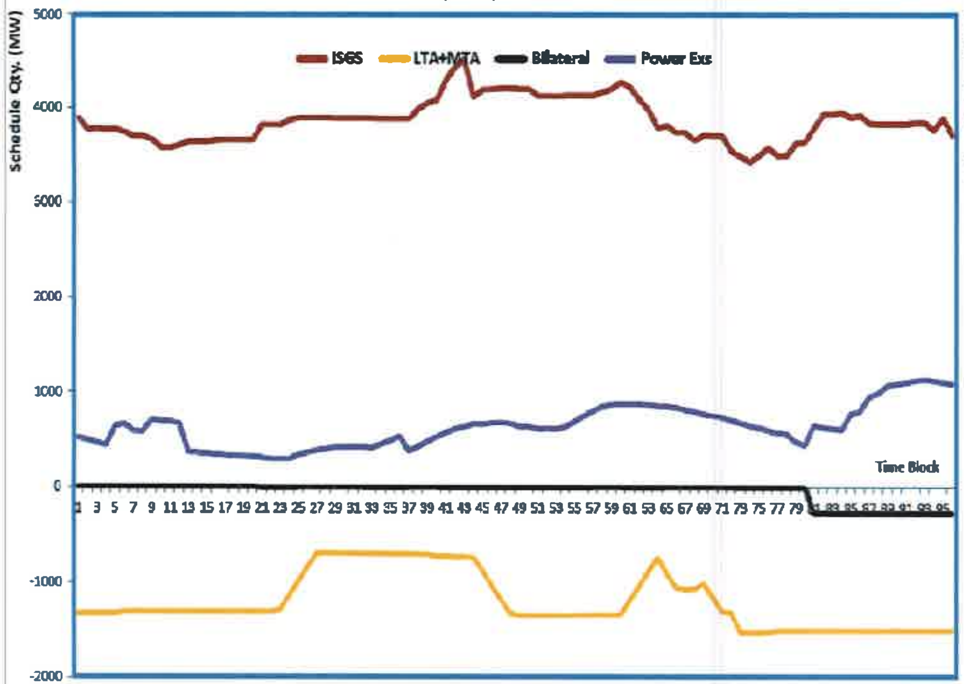

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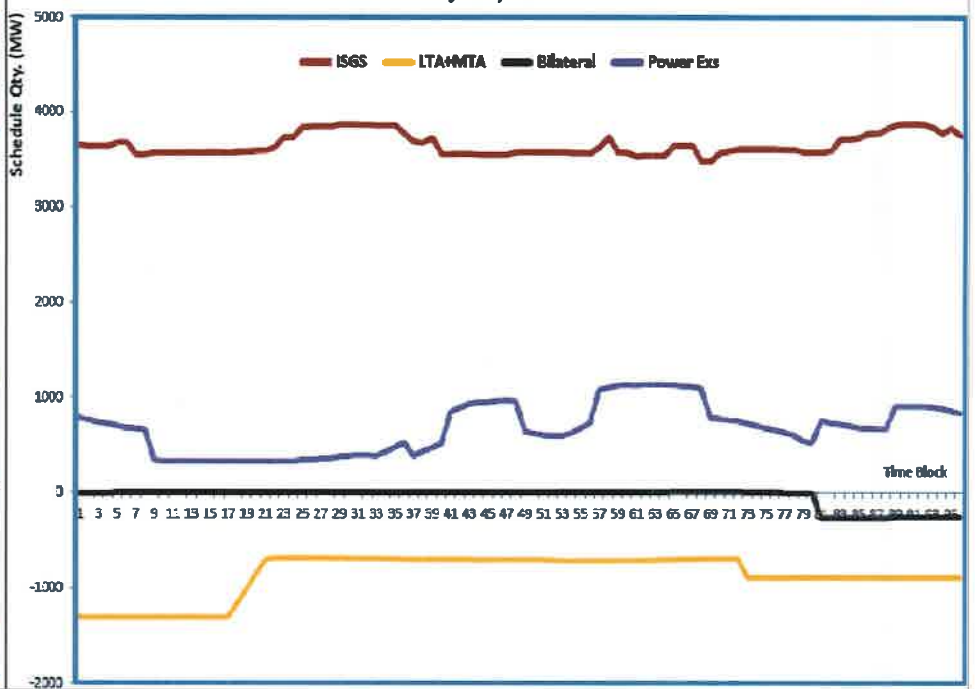

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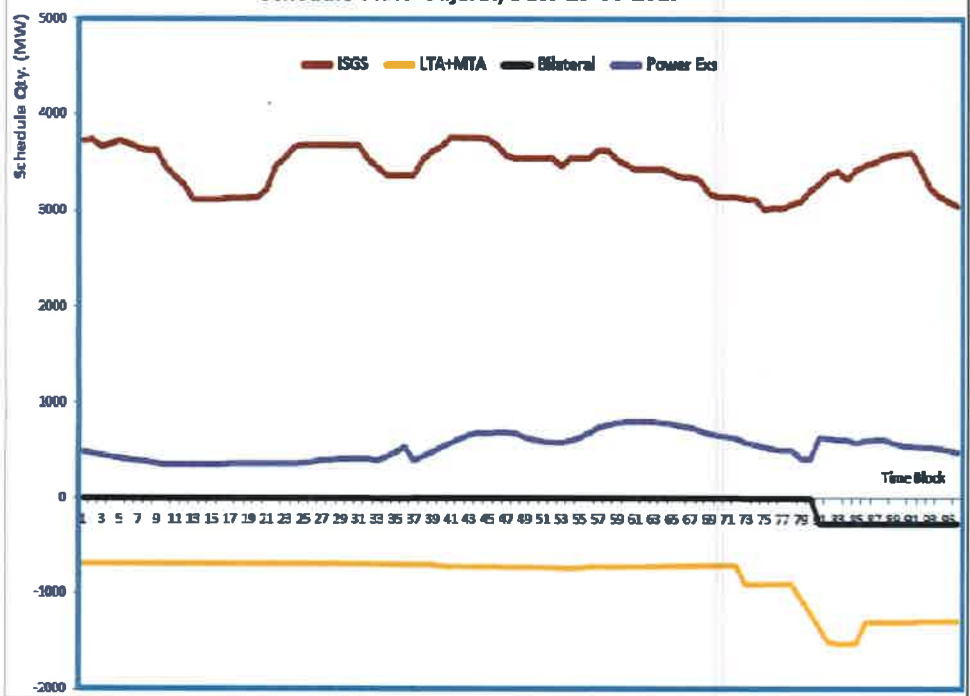

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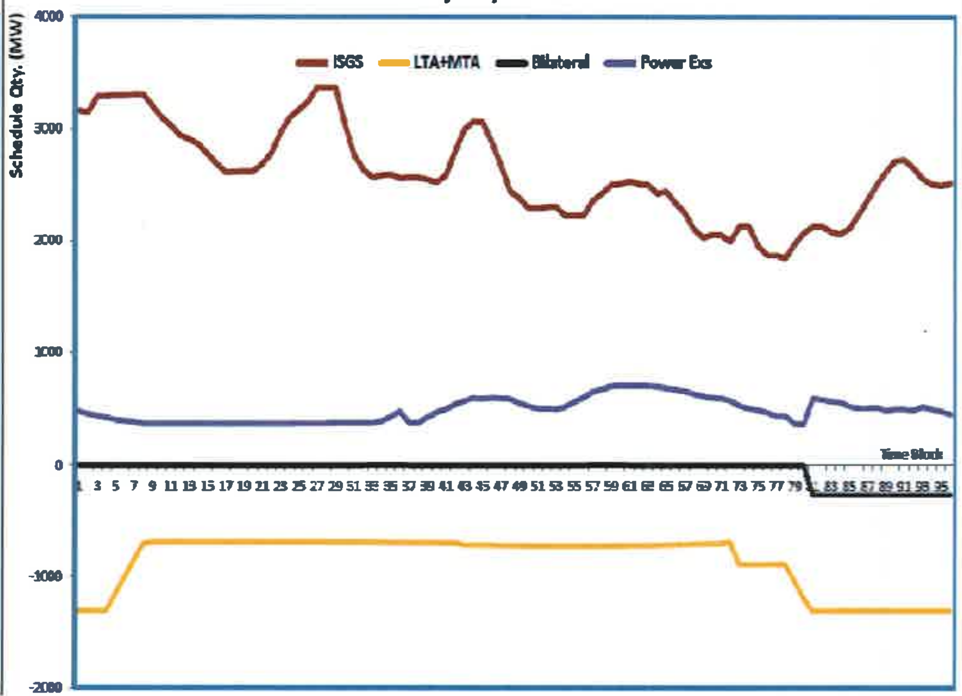

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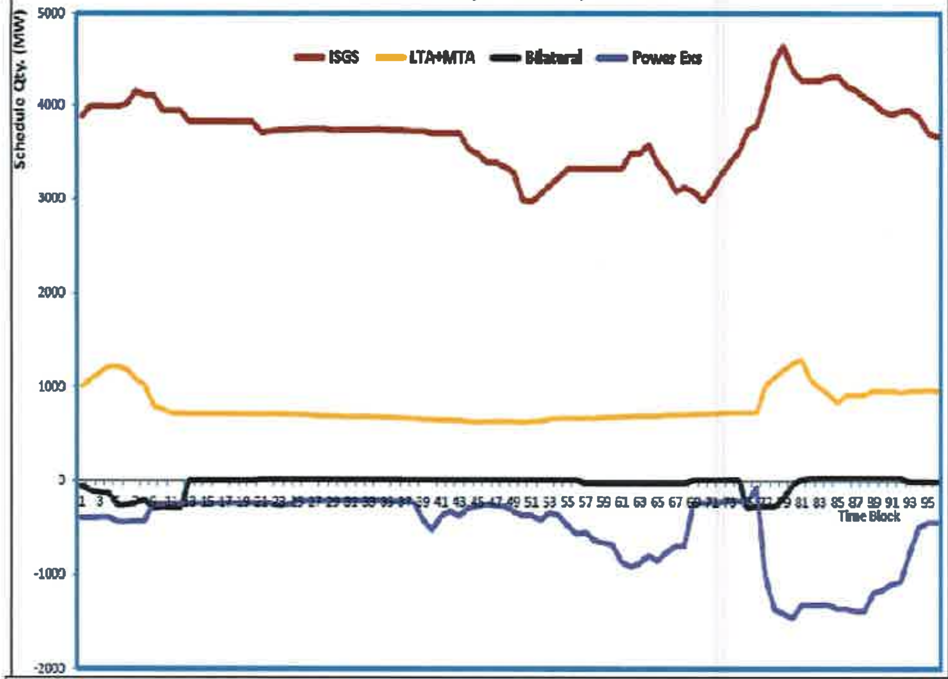

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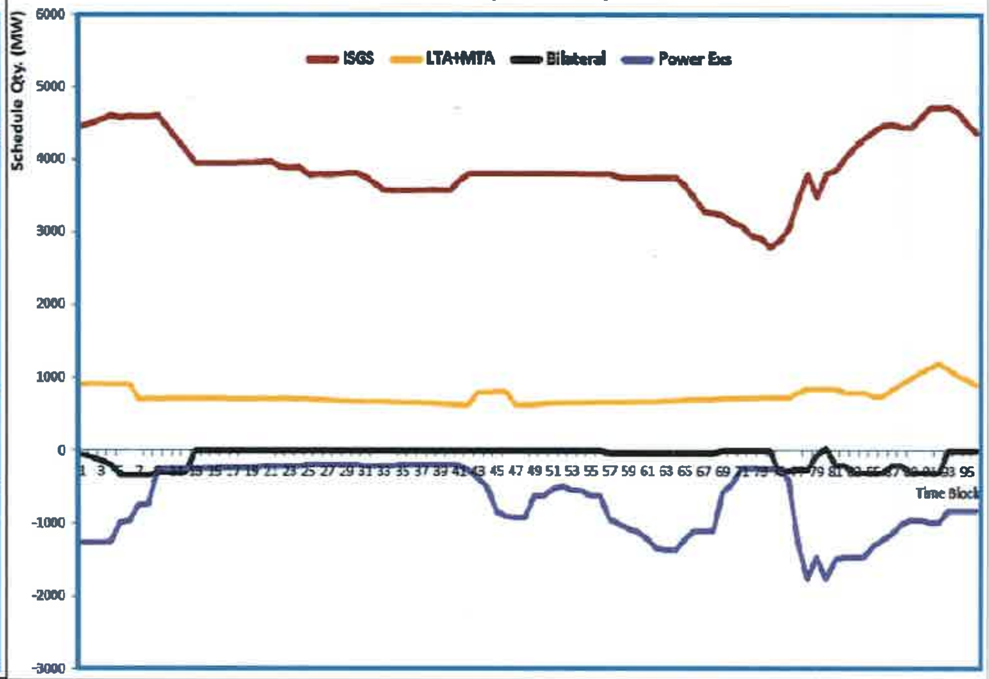

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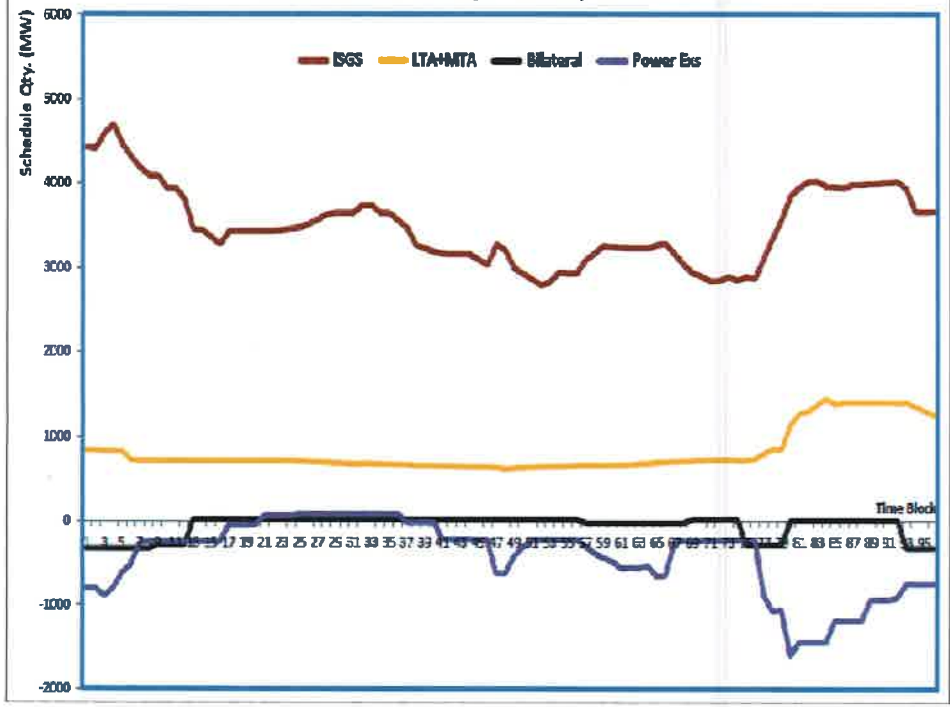

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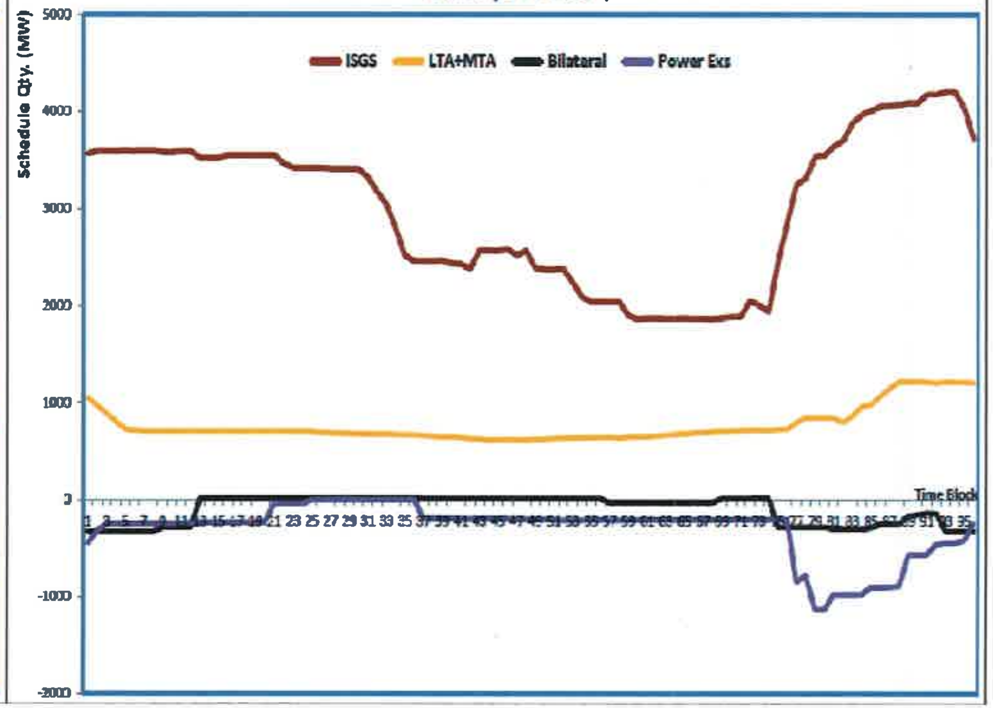
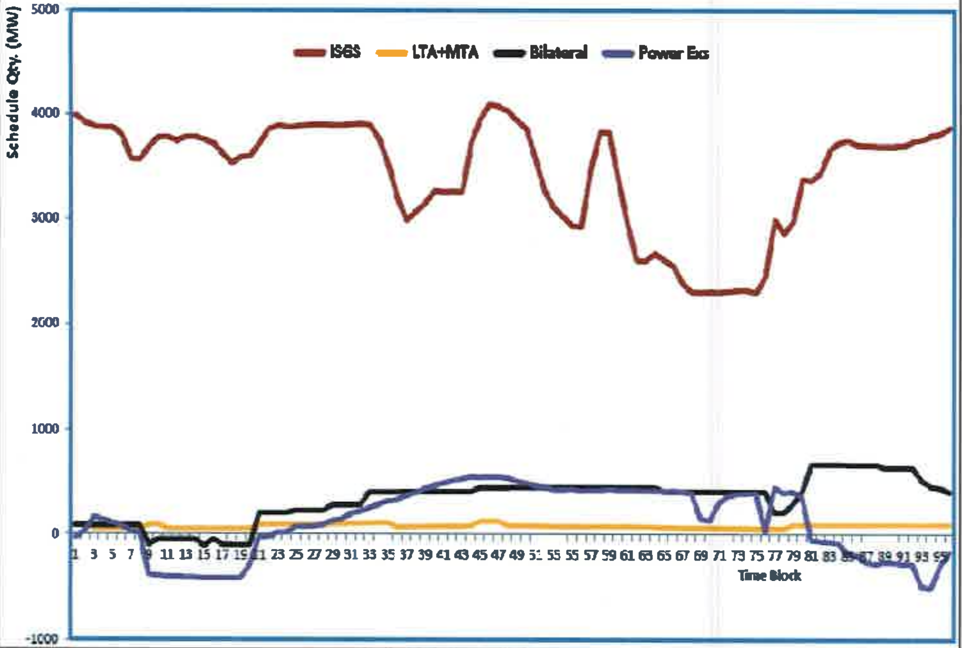


Schedule State-Maharashtra, Date-27-06-2017



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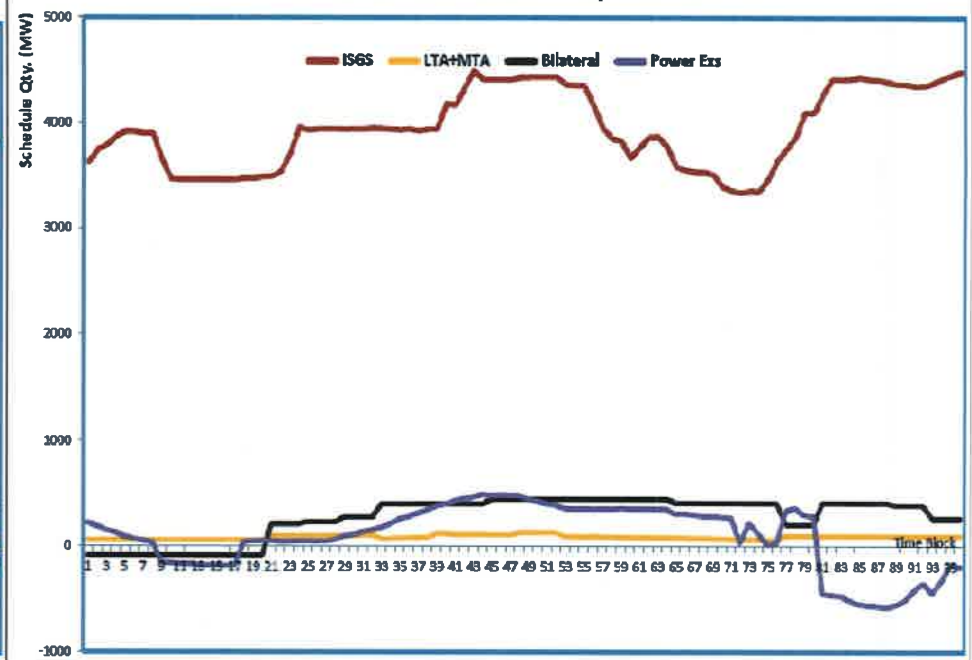

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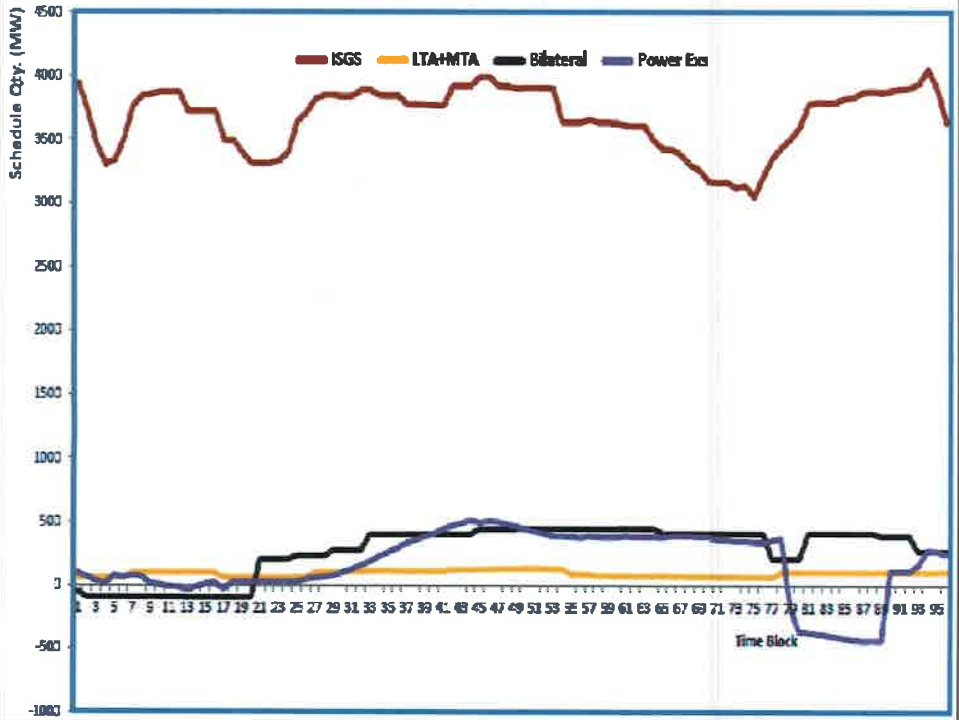

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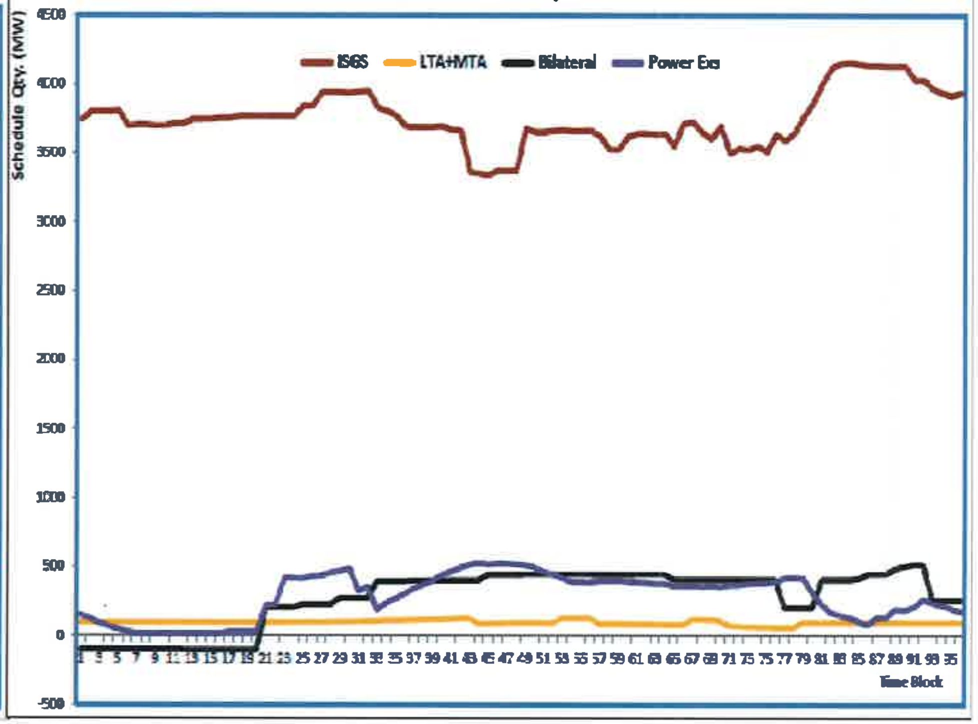
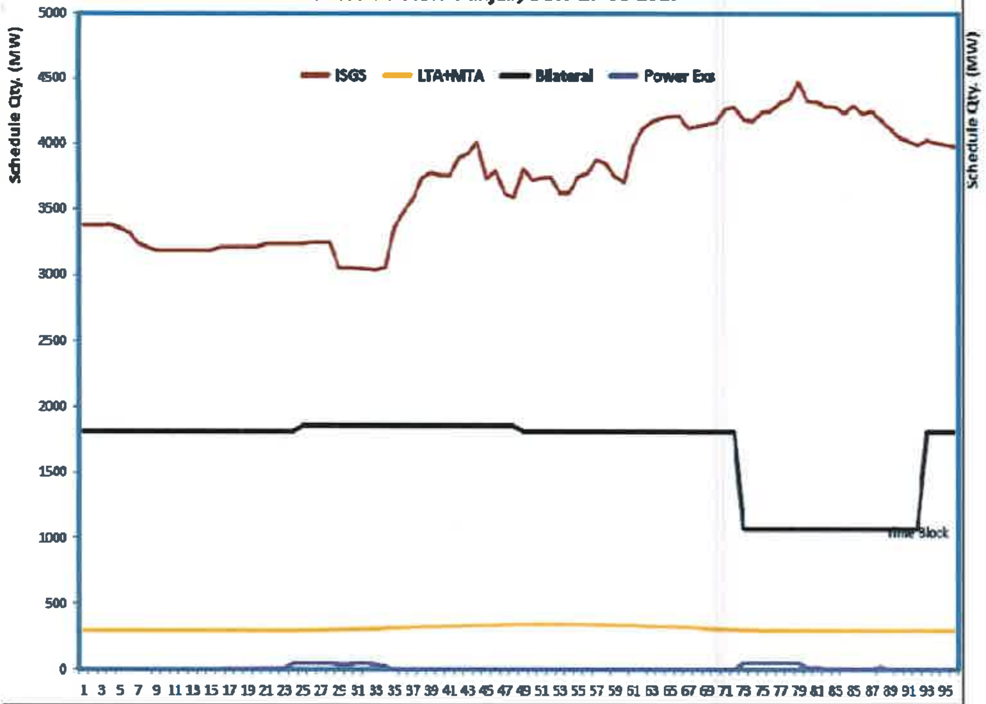


Schedule State-Punjab, Date-27-06-2017



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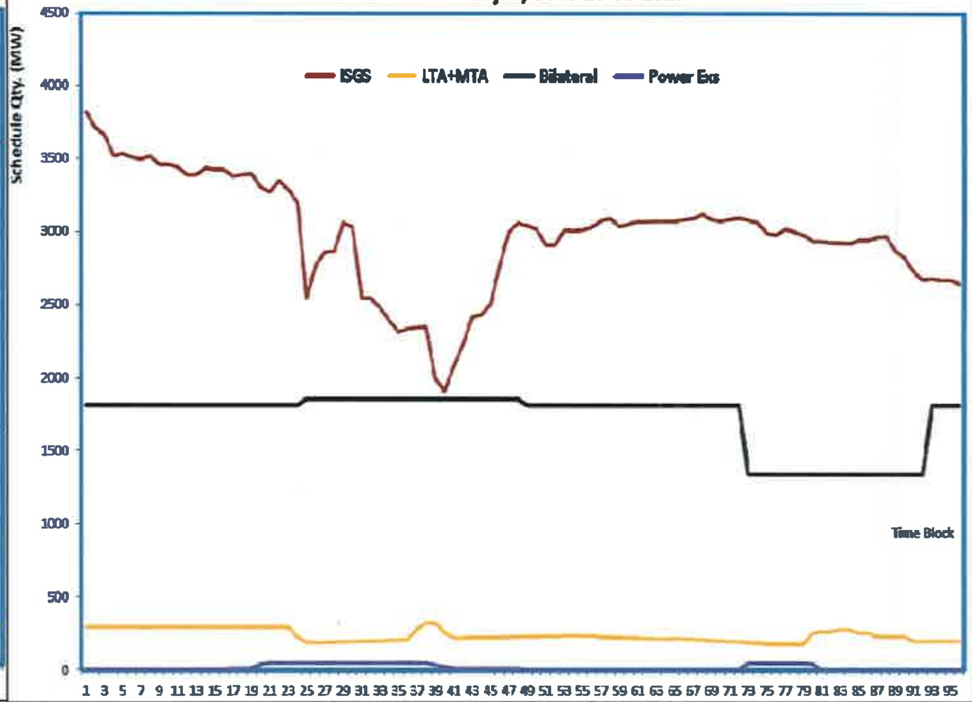

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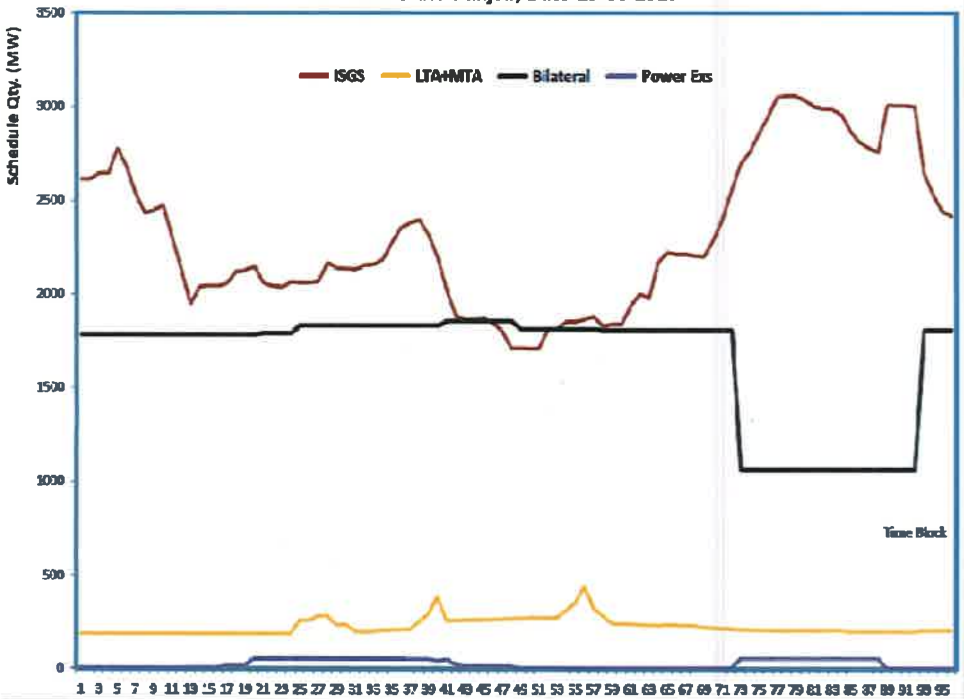

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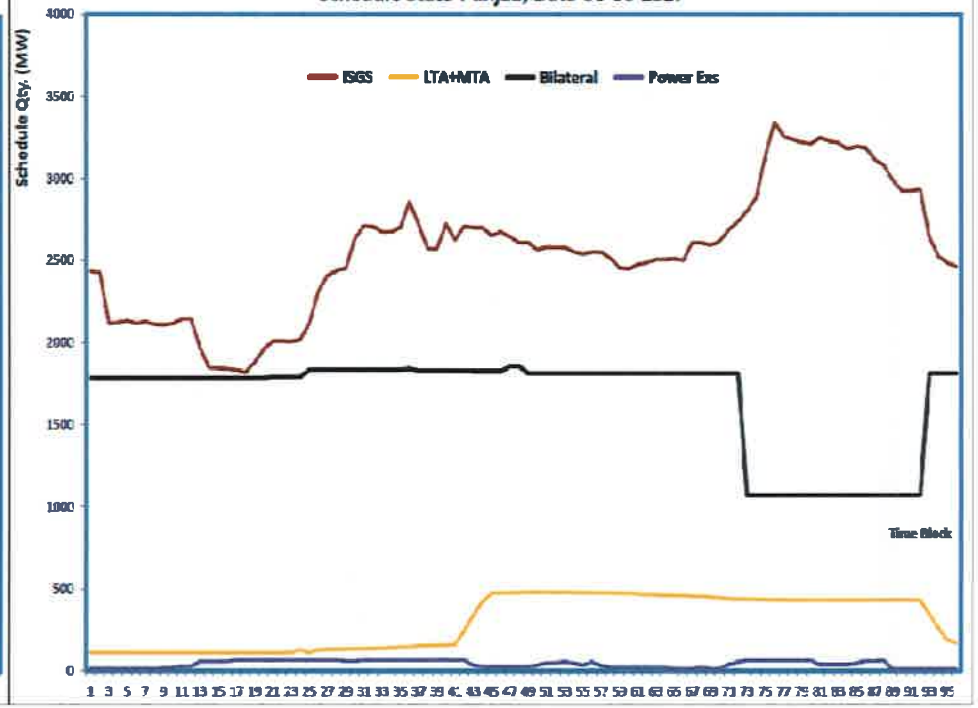
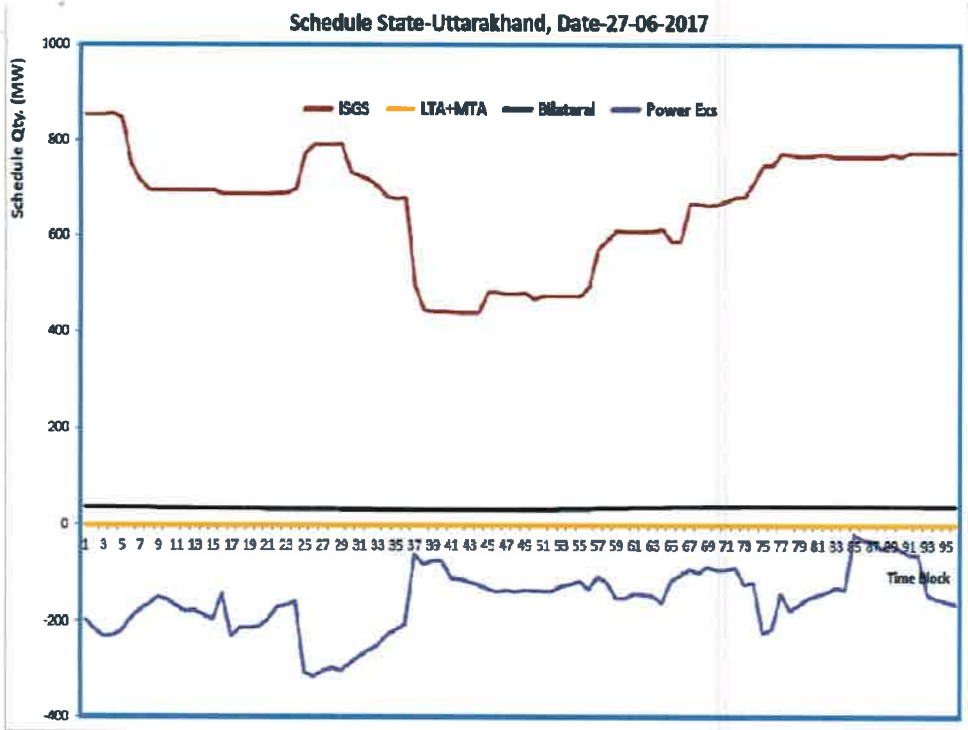
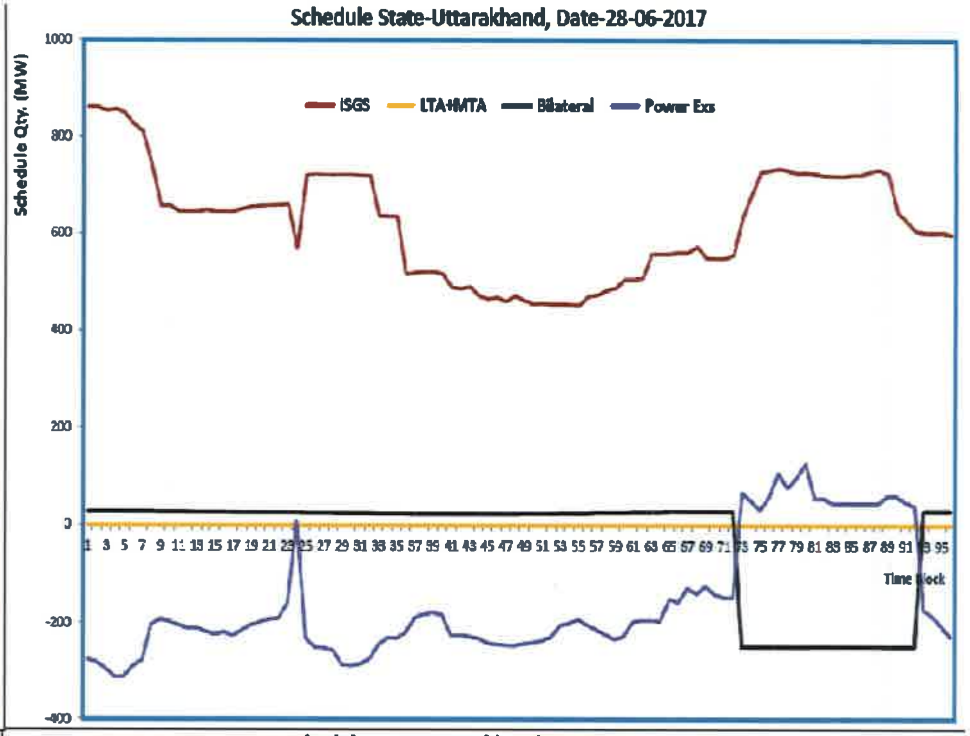



Schedule State-Uttarakhand, Date-27-06-2017
ISGS
LTA+MTA
Bilateral
Power Exs
Schedule Qty. (MW)
Time Block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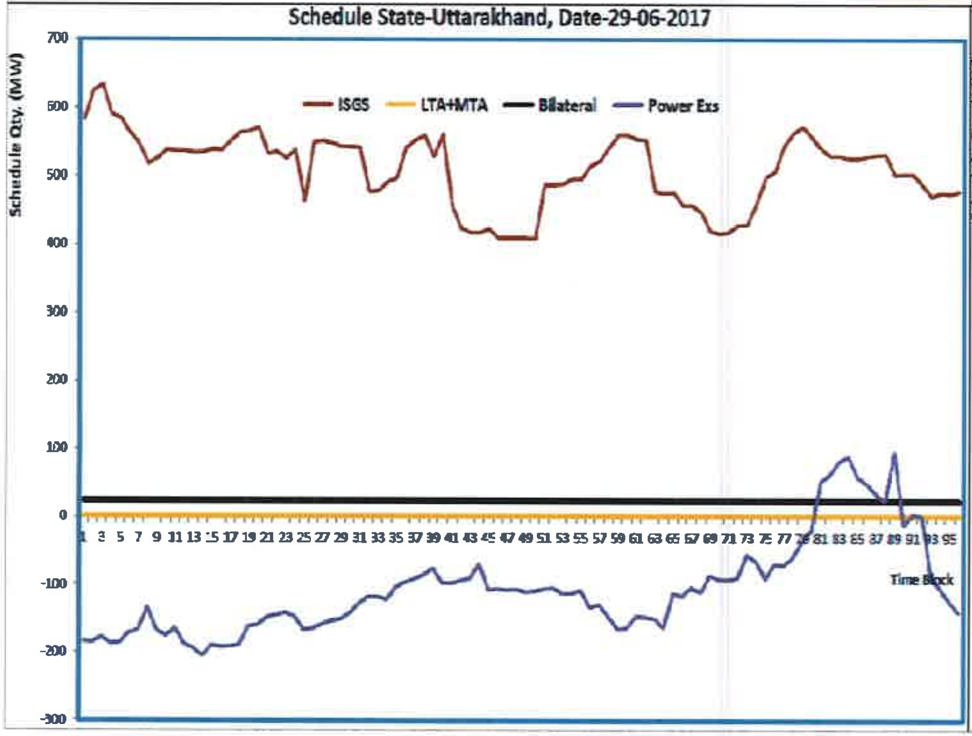
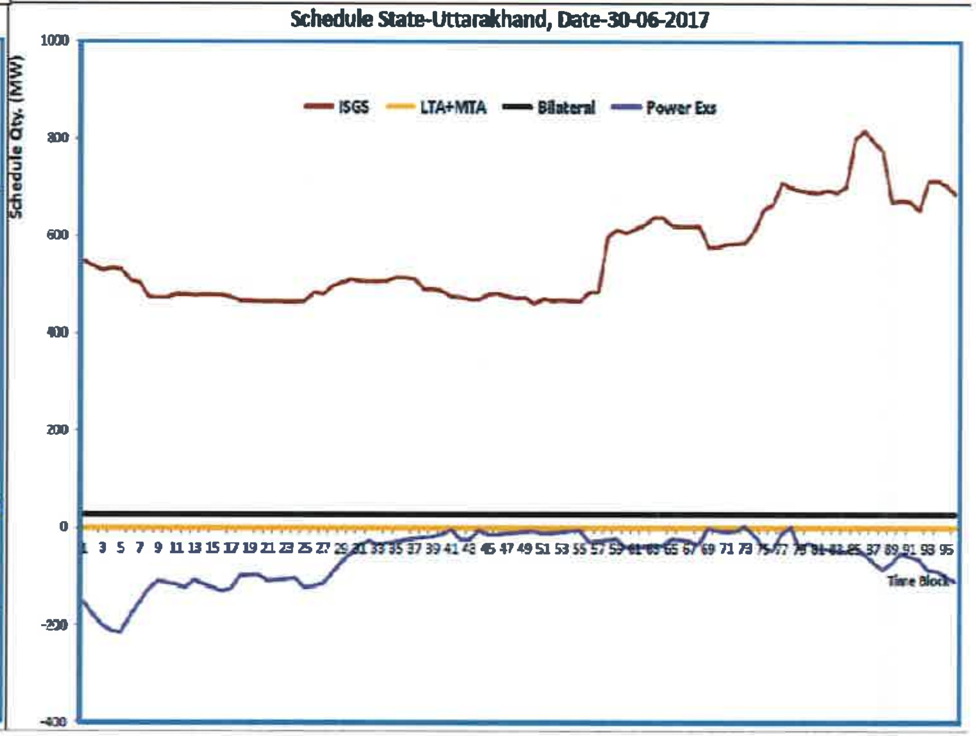
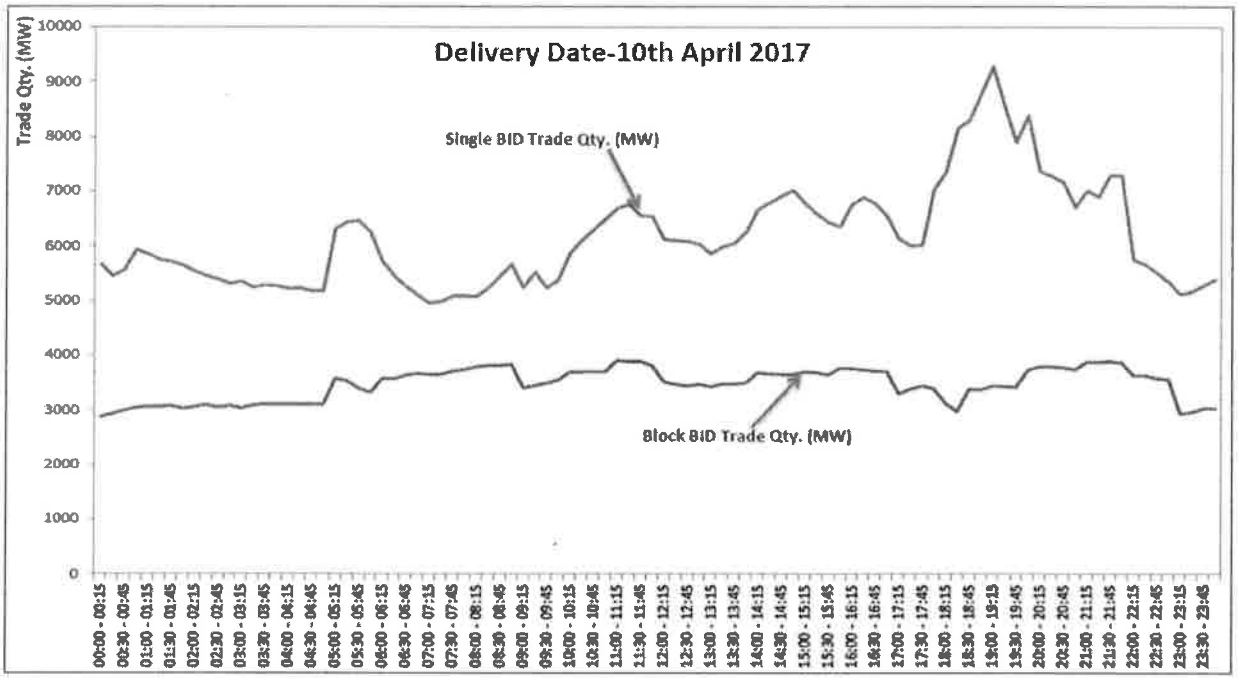
ISGS
LTA+MTA
Bilateral
Power Exs
Schedule Qty. (MW)
Time Block

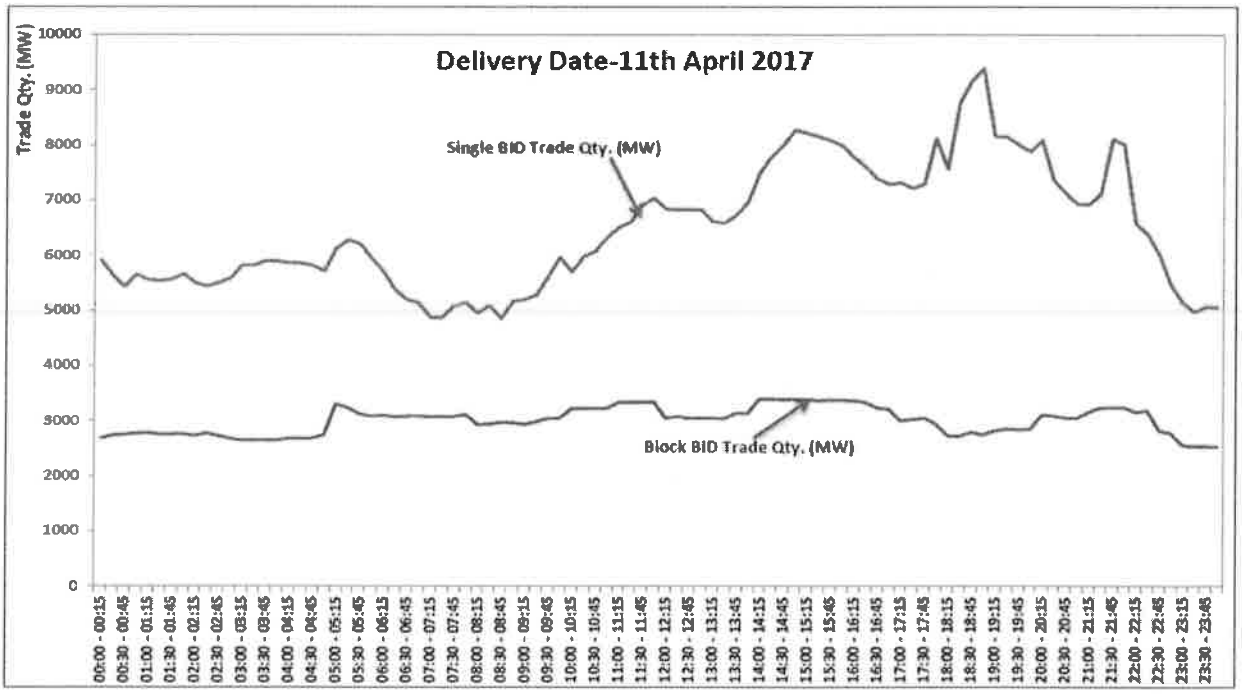

Schedule State-Uttarakhand, Date-29-06-2017
ISGS
LTA+MTA
Bilateral
Power Exs
Schedule Qty. (MW)
Time Block

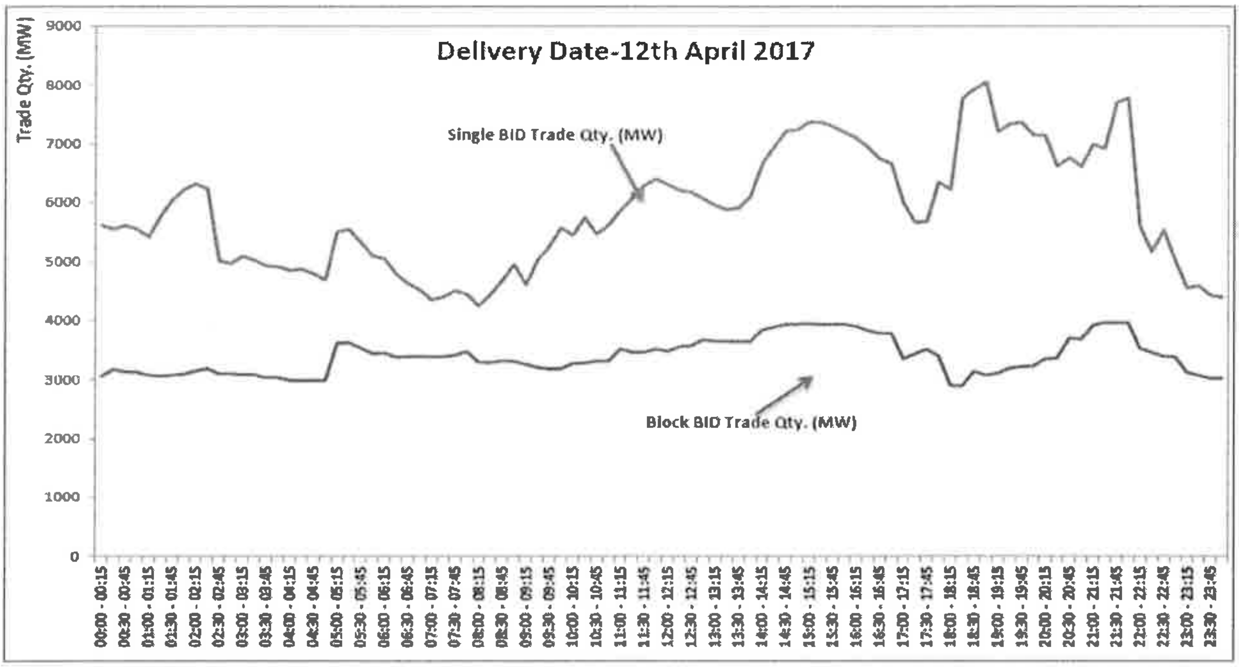

Schedule State-Uttarakhand, Date-30-06-2017
ISGS
LTA+MTA
Bilateral
Power Exs
Schedule Qty. (MW)
Time Block

Annexure-IV B

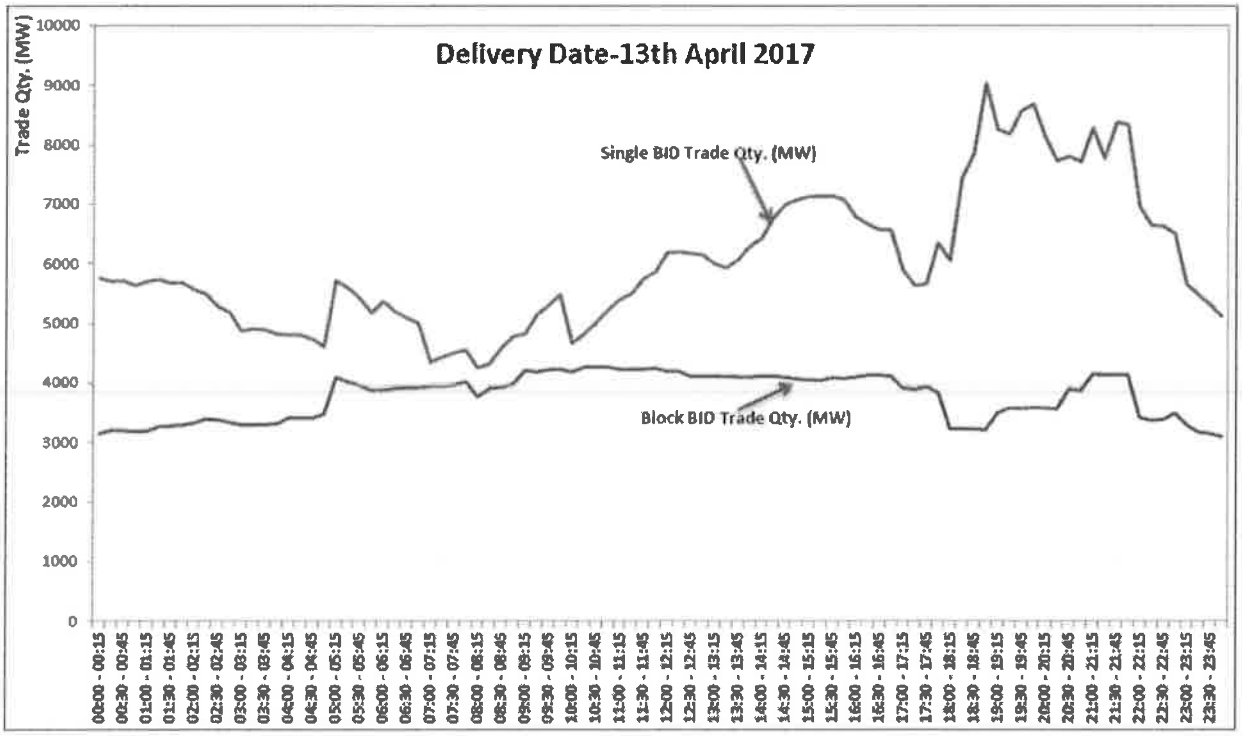
A. 3 Days Status Before Launch of Block Bid> 50 MW

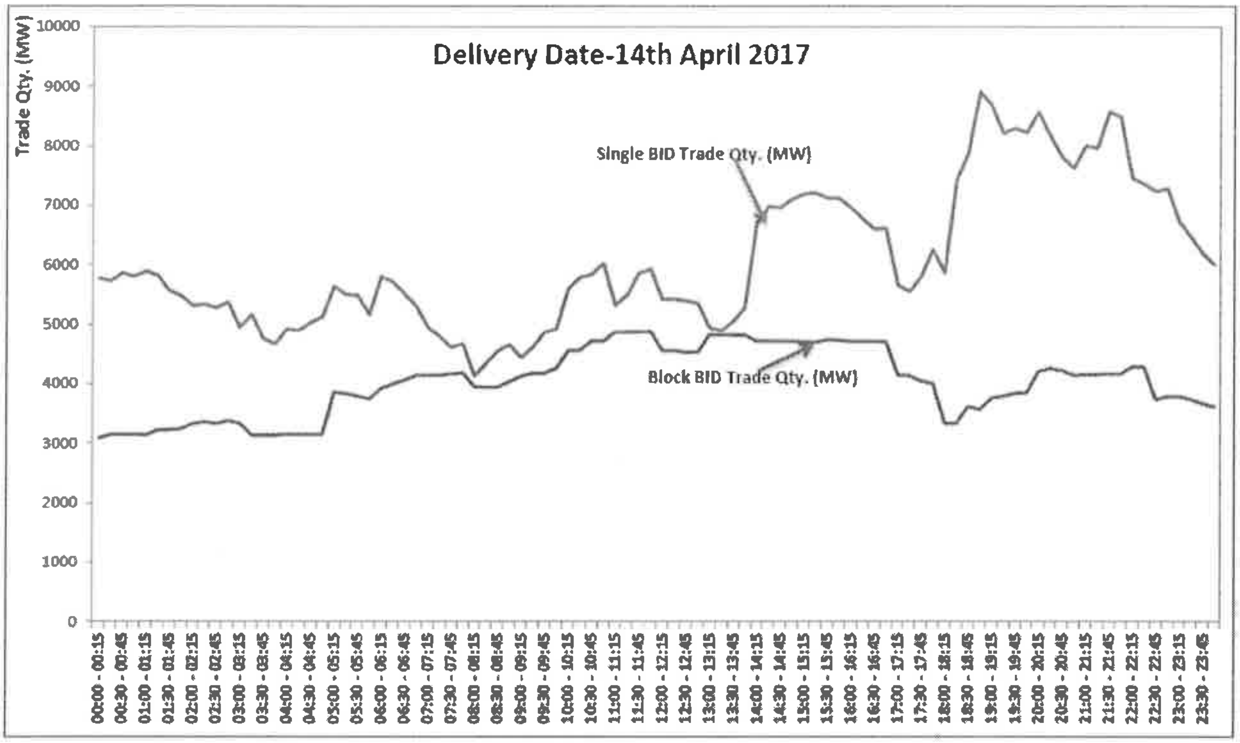


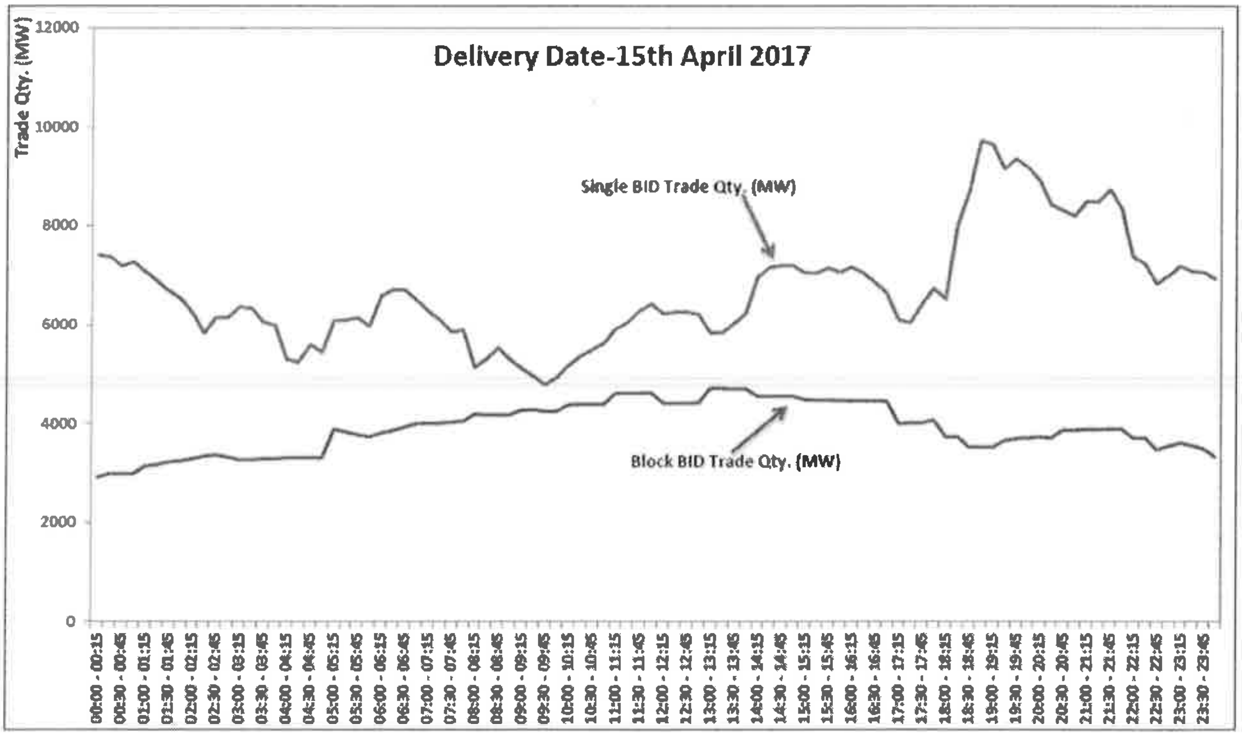




B. **3 Days Status After Launch of Block Bid> 50 MW**




Delivery Date-14th April 2017
Trade Qty. (MW)
Single BID Trade Qty. (MW)
Block BID Trade Qty. (MW)


Delivery Date-15th April 2017
Trade Qty. (MW)
Single BID Trade Qty. (MW)
Block BID Trade Qty. (MW)

ANNEXURE 5

Advanced Bid Structures

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Department of Electrical Engineering
IIT-Bombay

September 7, 2017

Reason for Introduction of Block Bids

- Encourage participation of generators with high startup and shutdown cost
- Guaranty on volume and operation over consecutive hours allows to bid competitive price
- Consider a generator with marginal cost of 5 per unit and fixed cost of 200, maximum volume of 50
  - Operation over single hour and full volume leads to price of $(200 + 50 \times 5)/50 = 9$
  - Operation over four consecutive hours and full volume leads to price of $(200 + 50 \times 5 \times 4)/(5 \times 4) = 6$

Problems with Block Bids

- Possibility of paradoxically rejection, especially during liquidity crunch
- Reducing volume increases bid price
- Volume rigidity is a problem

Flexible Structures I

- Allow volume flexibility
- Time flexibility can also be explored
- Minimum income criteria for bid clearing

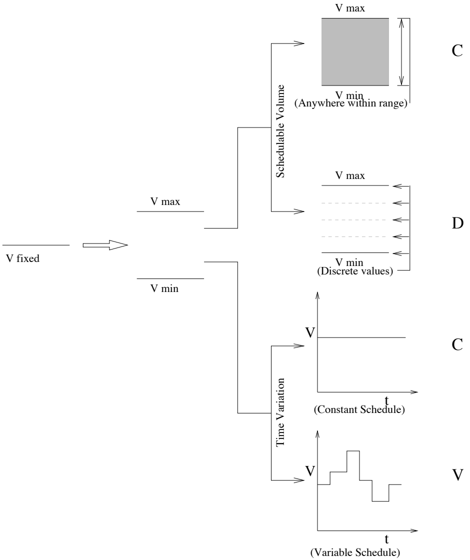

Figure: From fixed volume to flexible range.

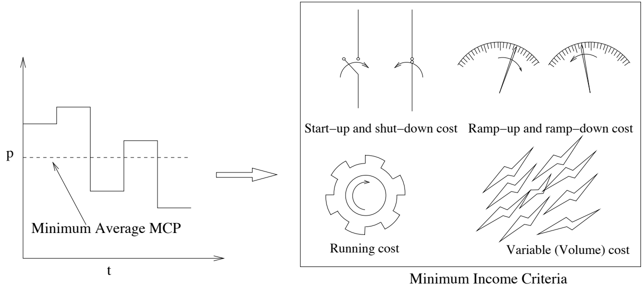

Figure: From minimum average price to minimum income criteria.

MILP Modelling

- Constant Marginal Price
- Stepped Marginal Price with FAK steps
- Stepped Marginal Price with FOK steps

MILP Modelling I

Constant Marginal Price

Specifications:

- Fixed cost to account for startup ($\alpha^{\uparrow}$) and shutdown ($\alpha^{\downarrow}$),
- Fixed running cost (ω), proportional to the time being in service, and,
- Variable cost (β) proportional to amount of power delivered.

MILP Modelling II

Constant Marginal Price

Constant volume operation

- Volume scheduling constraint
  - If a bid is not selected, the scheduled volume $V = 0$,
  - If bid is selected, the $V_{min} \leq V \leq V_{max}$

  This constraint can be modelled as follows:

$$sV_{min} \leq V \leq sV_{max}$$

- Minimum cost recovering constraint
  - If a bid is not selected, there is no cost to be recovered,
  - If a bid is selected with scheduled volume V, the minimum cost to be recovered is

$$\alpha^{\uparrow} + \alpha^{\downarrow} + (h_2 - h_1 + 1)\,\omega + (h_2 - h_1 + 1)\beta V$$

$$V \sum_{h=h_1}^{h_2} \pi_h^p \geq s(\alpha^{\uparrow} + \alpha^{\downarrow}) + s(h_2 - h_1 + 1)\,\omega + (h_2 - h_1 + 1)\beta V$$

MILP Modelling I

Variable Volume Schedule

- $V_h \in \mathcal{R}^+$ as a scheduled volume variable for each time slot $h \in \{h_1, h_1+1, \cdots, h_2\}$
- Slight modification over previous model

$$sV_{min} \leq V_h \leq sV_{max} \quad \forall h \in \{h_1, h_1+1, \cdots, h_2\}$$

$$\sum_{h=h_1}^{h_2} \pi_h^p V_h \geq s(\alpha^{\uparrow} + \alpha^{\downarrow}) + s(h_2 - h_1 + 1)\,\omega + \beta \sum_{h=h_1}^{h_2} V_h$$

MILP Modelling I

Stepped Marginal Cost (FAK Steps)

Specifications:

Fixed Cost			Volume	
Start Up	Shut Down	Running	Minimum	Maximum
$\alpha^{\uparrow}$	$\alpha^{\downarrow}$	ω	V_{min}	V_{max}

Price	β_1	β_2	....	β_m
Volume	V_1^b	V_2^b	....	V_m^b

Also, $\beta_1 < \beta_2 < \ldots < \beta_m$.

MILP Modelling II

Stepped Marginal Cost (FAK Steps)

Constant volume operation

- $V_i \in \mathcal{R}^+$ variable volume scheduled for each price step, i.e, $i \in \{1, 2, \cdots, m\}$.
- $V \in \mathcal{R}^+$ net volume scheduled.
- $s_i \in \mathcal{B}$ selection of i^{th} bid step.
- $s \in \mathcal{B}$ overall selection of bid, whether full or partial.

MILP Modelling III

Stepped Marginal Cost (FAK Steps)

- Volume scheduling constraint
  - Volume range

$$sV_{min} \leq V \leq sV_{max}$$

  - Scheduled volume sum of all steps' volume scheduled

$$V = \sum_{i=1}^{m} V_i$$

  - Step volume range

$$0 \leq V_i \leq s_i V_i^b, \quad \forall i \in \{1, 2, 3, \ldots, m\}$$

  - Eligibility of higher step

$$s_i \leq \frac{V_{i-1}}{V_{i-1}^b}, \quad \forall i \in \{2, 3, \ldots, m\}$$

  - Relation between bid selection and lowest step selection

$$s = s_1$$

MILP Modelling IV

Stepped Marginal Cost (FAK Steps)

- Minimum cost recovery constraint

$$V \sum_{h=h_1}^{h_2} \pi_h^p \geq s(\alpha^{\uparrow} + \alpha^{\downarrow}) + s(h_2 - h_1 + 1)\,\omega + (h_2 - h_1 + 1) \sum_{i=1}^{m} \beta_i V_i$$

MILP Modelling V

Stepped Marginal Cost (FAK Steps)

Variable volume operation

$$sV_{min} \leq V_h \leq sV_{max}$$

$$V_h = \sum_{i=1}^{m} V_i^h$$

$$0 \leq V_i^h \leq s_i^h V_i^b$$

$$s_i^h \leq s_{i-1}^h, \quad \forall i \in \{2, 3, \ldots, m\}$$

$$s = s_1^h$$

$$\sum_{h=h_1}^{h_2} \pi_h^p V_h \geq s(\alpha^{\uparrow} + \alpha^{\downarrow}) + s(h_2 - h_1 + 1)\,\omega + \sum_{h=h_1}^{h_2} \sum_{i=1}^{m} \beta_i V_i^h$$

MILP Modelling I

Stepped Marginal Cost (FOK Steps)

Constant volume operation

- $V_i \in \mathcal{R}^+$ volume variable scheduled for each price step, i.e, $i \in \{1, 2, \cdots, m\}$.
- $V \in \mathcal{R}^+$ net volume scheduled.
- $s_i \in \mathcal{B}$ selection of i^{th} bid step.
- $s \in \mathcal{B}$ overall selection of bid, whether full or partial.
- $\zeta_i \in \mathcal{R}^+$ value obtained from the market through step, i.e, $i \in \{1, 2, \cdots, m\}$.

MILP Modelling II

Stepped Marginal Cost (FOK Steps)

- Volume scheduling constraint
  - Net volume range

$$sV_{min} \leq V \leq sV_{max}$$

  - Scheduled volume sum of individial step's schedule

$$V = \sum_{i=1}^{m} V_i$$

  - Step volume range

$$V_i = s_i V_i^b$$

  - Eligibility of higher steps

$$s_i \leq s_{i-1} \quad \forall i \in \{2, 3, \ldots, m\}$$

  - Bid selection implies lowest step being selected

$$s = s_1$$

MILP Modelling III

Stepped Marginal Cost (FOK Steps)

- Minimum cost recovering constraint
  - Value earned

$$0 \leq \zeta_i \leq s_i M$$

$$-(1 - s_i)\mathbf{M} \leq \zeta_i - V_i^b \sum_{h=h_1}^{h_2} \pi_h^p \leq (1 - s_i)\mathbf{M}$$

  - Minimum income criteria

$$\sum_{i=1}^{m} \zeta_i \geq s(\alpha^{\uparrow} + \alpha^{\downarrow}) + s(h_2 - h_1 + 1)\,\omega + (h_2 - h_1 + 1)\sum_{i=1}^{m} \beta_i V_i$$

MILP Modelling IV

Stepped Marginal Cost (FOK Steps)

Variable volume operation

- $V_i^h \in \mathcal{R}^+$ volume scheduled for each price step and each time slot,
- $V_h \in \mathcal{R}^+$ net volume scheduled, for h^{th} time slot,
- $s_i^h \in \mathcal{B}$ selection of i^{th} bid step,
- $s \in \mathcal{B}$ overall selection of bid, whether full or partial, and,
- $\zeta_i^h \in \mathcal{R}^+$ value obtained for i^{th} step in h^{th} hour.

MILP Modelling V

Stepped Marginal Cost (FOK Steps)

Constraints

$$sV_{min} \leq V_h \leq sV_{max}$$

$$V_h = \sum_{i=1}^{m} V_i^h$$

$$V_i^h = s_i^h V_i^b$$

$$s_i^h \leq s_{i-1}^h, \quad \forall i \in \{2, 3, \ldots, m\}$$

$$s = s_1^h$$

$$0 \leq \zeta_i^h \leq s_i^h M$$

$$-(1 - s_i^h)\mathbf{M} \leq \zeta_i^h - V_i^h \pi_h^p \leq (1 - s_i^h)\mathbf{M}$$

$$\sum_{h=h_1}^{h_2} \sum_{i=1}^{m} \zeta_i^h \geq s(\alpha^{\uparrow} + \alpha^{\downarrow}) + s(h_2 - h_1 + 1)\,\omega + \sum_{h=h_1}^{h_2} \sum_{i=1}^{m} \beta_i V_i^h$$

MILP Modelling I

Accounting for Ramping Cost

Assumption: Ramping cost proportional to change in volume

$$C_{ramp} = \gamma^{\uparrow}(V_h - V_{h-1}) \quad \text{if } V_i \geq V_{i-1}$$
$$C_{ramp} = \gamma^{\downarrow}(V_{h-1} - V_h) \quad \text{if } V_{i-1} \geq V_i$$

MILP Modelling II

Accounting for Ramping Cost

Constant volume operation

- Term $(\gamma^{\uparrow} + \gamma^{\downarrow})V$ has to be added to the expression representing minimum cost to be recovered
- For example, under fixed marginal cost

$$V \sum_{h=h_1}^{h_2} \pi_h^p \geq s(\alpha^{\uparrow} + \alpha^{\downarrow}) + s(h_2 - h_1 + 1)\,\omega + (h_2 - h_1 + 1)\beta V + (\gamma^{\uparrow} + \gamma^{\downarrow})V$$

MILP Modelling III

Accounting for Ramping Cost

Variable volume operation

- Introduce C_h^{ramp} as cost of ramping from time slot $h-1$ to h
- Ramping costs for each transition

$$C_h^{ramp} \geq \gamma^{\uparrow}(V_h - V_{h-1}) \quad \forall h \in \{h_1+1, h_1+2, \cdots, h_2\}$$
$$C_h^{ramp} \geq \gamma^{\downarrow}(V_{h-1} - V_h) \quad \forall h \in \{h_1+1, h_1+1, \cdots, h_2\}$$
$$C_{h_1}^{ramp} = \gamma^{\uparrow}\, V_{h_1}$$
$$C_{h_2+1}^{ramp} = \gamma^{\downarrow}\, V_{h_2}$$

- Add to minimum income expression; in case of fixed marginal cost model

$$\sum_{h=h_1}^{h_2} \pi_h^p V_h \geq s(\alpha^{\uparrow} + \alpha^{\downarrow}) + s(h_2 - h_1 + 1)\,\omega + \beta \sum_{h=h_1}^{h_2} V_h + \sum_{h=h_1}^{h_2+1} C_h^{ramp}$$

MILP Modelling I

Multiple Start up and Shutdown

Variables

- s_h to model switching in each time slot
- $s_h^{\uparrow}$ and $s_h^{\downarrow}$ to model switch transition in that time slot

Detection of switching

- In each time slot h, the generator might be maintaining its previous state or it may switch from off to on or on to off

$$s_h^{\uparrow} + s_h^{\downarrow} \leq 1$$

- Switch transition from off to on

$$s_h^{\uparrow} \geq s_h - s_{h-1}$$

- Switch transition on to off

$$s_h^{\downarrow} \geq s_{h-1} - s_h$$

MILP Modelling II

Multiple Start up and Shutdown

- No switch transition

$$s_h^{\uparrow} + s_h^{\downarrow} \leq s_{h-1} + s_h$$
$$s_h^{\uparrow} + s_h^{\downarrow} \leq 2 - s_{h-1} - s_h$$

- Initial and final switch state is off

$$s_{h_1-1} = s_{h_2+1} = 0$$

MILP Modelling III

Multiple Start up and Shutdown

Contribution to minimum cost

- Replace expression for fixed cost, $s(\alpha^{\uparrow} + \alpha^{\downarrow})$, by

$$\alpha^{\uparrow} \sum_{h=h_1}^{h_2} s_h^{\uparrow} + \alpha^{\downarrow} \sum_{h=h_1}^{h_2} s_h^{\downarrow}$$

- Replace fixed running cost, $s(h_2 - h_1 + 1)\,\omega$, by

$$\omega \sum_{h=h_1}^{h_2} s_h$$

MILP Modelling I

Linear Approximation of Quadratic Term

- Discretize volume with resolution of ΔV
- Volume representation

$$V = S_s V^{min} + \sum_{g=1}^{m} s_g 2^{g-1} \Delta V$$

- Income criteria from first block of V^{min}

$$-(1 - S_s)M \leq C_s^0 - V^{min} \sum_{h=h_1}^{h_2} MCP(h) \leq (1 - S_s)M$$

$$-S_s M \leq C_s^0 \leq S_s M$$

MILP Modelling II

Linear Approximation of Quadratic Term

- Income criteria through each delta block

$$-(1 - s_g)M \leq C_s^g - (2^{g-1})\Delta V \sum_{h=h_1}^{h_2} MCP(h) \leq (1 - s_g)M$$

$$-s_g M \leq C_s^g \leq s_g M$$

- Any of these delta blocks is eligible for selection only if a main block has been selected

$$s_g \leq S_s$$

- Net income

$$C_s = \sum_{g=0}^{n} C_s^g$$

Case Studies I

Small Scale

Base Case: Normal Block Bids

	Buy		Sell		Block Sell	
Hr	Price	Volume	Price	Volume	Price	Volume
1	700	100	350	50	300	100
	600	150	380	150		
	550	200	—	—		
2	700	100	200	50		
	600	200	210	150		
	550	200	—	—		

Case Studies II

Small Scale

- The block bid is unable to be cleared,
- Both selling and buying bids clear at 150 volume for both hours,
- MCP for first hour comes out to be 575 and for second it is 600, and,
- Total traded volume is 300 with a net social welfare of 113500.

Case Studies III

Small Scale

Case I: Stepped Block Bid for Flexibility

- $\alpha^{\uparrow} = 20,000$, $\alpha^{\downarrow} = 20,000$
- $\beta = 100$
- Leads to minimum average price of 300
- Let operation possible at volume levels 50 and 100

Results

- Block bid is able to be scheduled for a total of 50 units of volume,
- Buy bid is scheduled to 200 in both hours and hourly selling bids to 150,
- MCP for the first hour comes out to be 475, while for second it is observed to be 600, and,
- Total traded volume in this case is 400 and net social welfare 121000.

Case Studies IV

Small Scale

Case II: Variable Schedule for Block Bid

- Able to sell the complete 100 unit in first hour
- In second hour 50 units is scheduled
- MCPs: 380 and 470
- Social welfare: 135000

Case Studies V

Small Scale

Case II: More Competition

- Hourly seller drops price for hour 1
  - Only one step of price 300 and volume 150
- In hour 2, one more level of bidding: 200 units of volume at a price of 350

Results

- Block bid unable to trade
- Social welfare: 136500
- Traded volume: 350

Case Studies VI

Small Scale

Case III: Block Bid More Competitive

- Marginal price of 50 for first 50 units of volume
- Marginal price remains 100 for delivering 100 units of volume

Results

- Block bid clears 50 units of volume in both hours
- Social welfare: 136500
- Traded volume: 400

Case Studies I

Performance on Large Scale

Test Cases

- Random generation of test cases
- Total number of hourly bid steps between 200 to 10000
- Advanced bids between 20 to 1000
- Advanced bid can have steps from 1 to 10
- Study over 20 cases

Termination Criteria

- Maximum computation time of 1 hour, and,
- Proximity to optimal solution within 0.01%.

Case Studies II

Performance on Large Scale

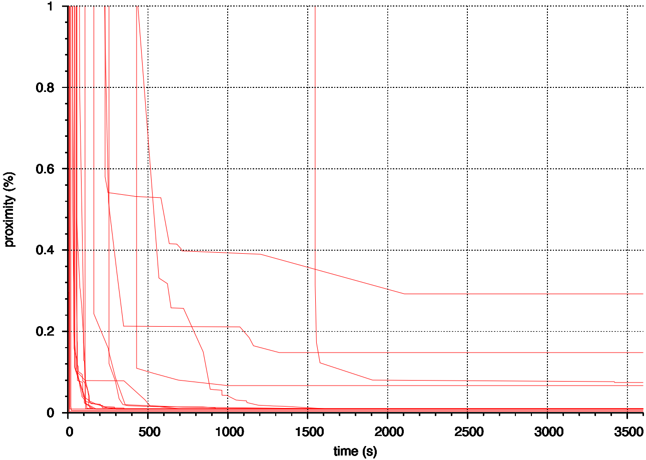

Figure: Convergence profile over various test cases.

Conclusions

- New flexible bid structures proposed as alternative to block bids
- Segregate cost components like startup, shutdown, running, ramping and marginal
- Allows block bidders to be even more competitive and probability of PRB comes down
- Large scale studies demonstrate practical feasibility

Thank You

Introduction to Power Exchange

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Indian Institute of Technology Bombay

July 13, 2017

Outline

Introduction

- Trading through an exchange enables the traders to discover the best price in the market and to find the optimum buyer or seller for trade.
- Power exchange introduces transparency in the market clearing and reduces counter-party credit risk.
- Exchange manages trades, clears market and settles financial transactions.
- Design and implementation issues of a power exchange or power market, in general, depend on the market supplies and demands, liquidity, economy etc.
- Philosophy of exchange design may vary from country to country or exchange to exchange (working in the same country).

Power Exchange Products

- Day Ahead Market
- Term Ahead Market
- Renewable Energy Certificates Trading

Power Exchange Products

- Day Ahead Market
  - Collective transactions
  - Type of bids: Hourly, Block
  - Inter-regional trading
- Term Ahead Market
- Renewable Energy Certificates Trading

Power Exchange Products

- Day Ahead Market
- Term Ahead Market
  - Bilateral Transactions
  - Regional market
  - Market types
    - Day ahead contingency market: single hourly bids
    - Intra- day market
    - Daily contracts: Base (24 hrs), Night off-peak (8 hrs), day (11 hrs) and Day peak (5 hrs) contracts
    - Weekly contracts: Base (7x24 hrs), Night off-peak (7x8 hrs), day (7x11 hrs) and Day peak (7x5 hrs) contracts
- Renewable Energy Certificates Trading

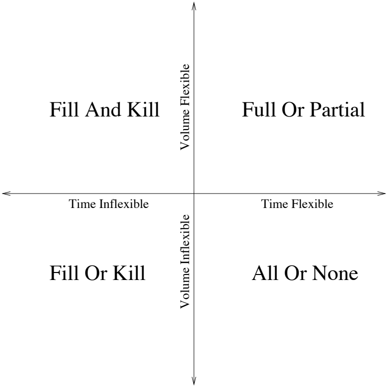
Power Exchange Products

- Day Ahead Market
- Term Ahead Market
- Renewable Energy Certificates Trading
  - Solar and Non-solar certificates
  - Green Attributes of 1MWh of electricity generated by eligible Renewable Generator allowed in CERC (Terms and Conditions for recognition and issuance of Renewable Energy Certificate for Renewable Energy Generation) Regulations, 2010

Power Exchange Products

- Day Ahead Market
- Term Ahead Market
- Renewable Energy Certificates Trading

Bid Order Types



Bid Structures Offered in Market

Hourly Bid

Hourly Bid: Trader has to mention

- Time of deliver, and,
- Maximum amount deliverable/consumable at various price levels (step function)

Properties:

- Selected volume can lie anywhere between 0 to maximum limit
- Form of FAK
- In case of seller, increasing price leads to delivery of more volume.
- In contrast buyer reduces his willingness to consume power with increase in price.
- Example:

Price	50	100	200	300	400
Offer (Actual)	100	150	180	180	200
Offer (Transformed)	100	50	30	0	20

Block Bid: Trader specifies

- Block of time for which volume will be delivered/consumed,
- Fixed volume for trade, and,
- Average limit price

Properties:

- Bid if selected will deliver/consume constant volume for continuously for specified block
- Bid might be under loss in one particular time slot, but may make enough profit to compensate in other time slot
- Form of FOK

Bid Structures Offered in Market

Linked Block Bid

Linked Block Bid Trader specifies

- All specifications as required by block bid, and,
- Block bid on acceptance of which only this bid can be considered for auction.

Bid Structures Offered in Market

Flexible Hourly Bid

Flexible Hourly Bid Trader specifies

- Fixed volume that can be delivered/consumed, and,
- Limit price

Properties:

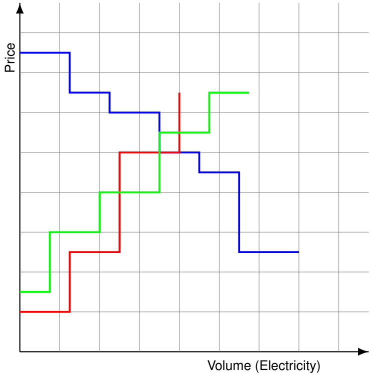
- Bid is considered for schedule in a time slot which has maximum/minimum MCP
- Might be rejected if best MCP over the day doesn't meet requirement of limit price
- Form of All-Or-None, though not purely

Market Clearing

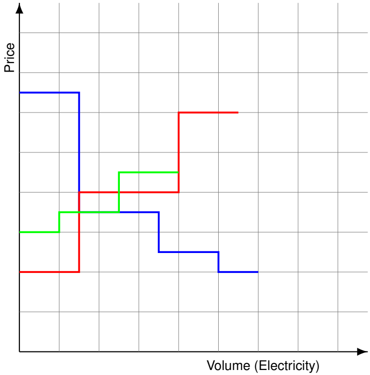
Hourly Bids

- Scheduling for each hour is decoupled of any other time slot
- Equilibrium at the intersection of buyer and seller curves; defines market clearing price (MCP) and market clearing volume (MCV)
  - Arrived schedule ensures that at MCP, each of the traders has maximized its surplus
- Also leads to maximization of social welfare (Consumer Surplus + Supplier Surplus)

Market Equilibrium: Graphical Visualization

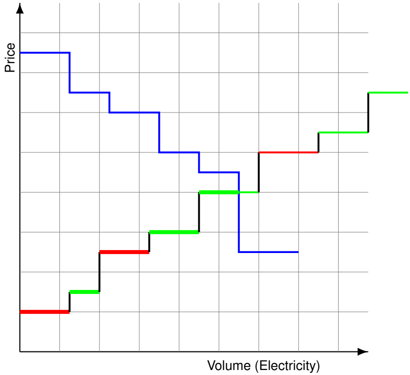


Hour 1

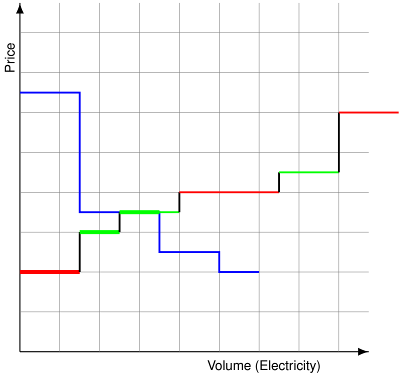


Hour 2

Market Equilibrium: Graphical Visualization

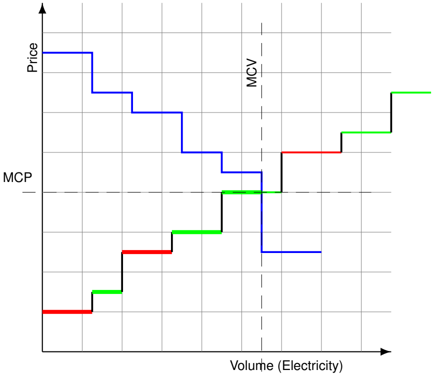


Hour 1

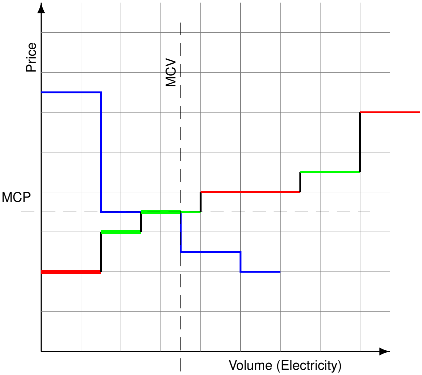


Hour 2

Market Equilibrium: Graphical Visualization

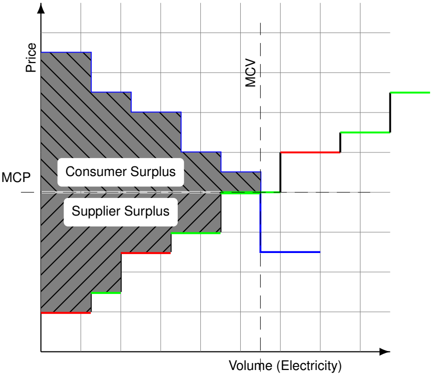


Hour 1

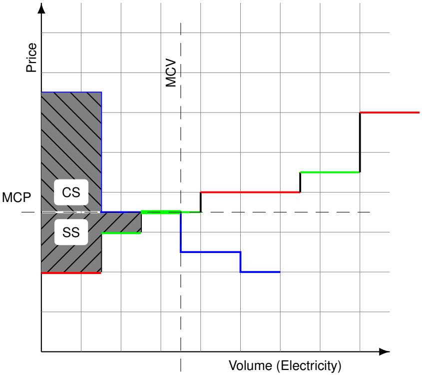


Hour 2

Market Equilibrium: Graphical Visualization

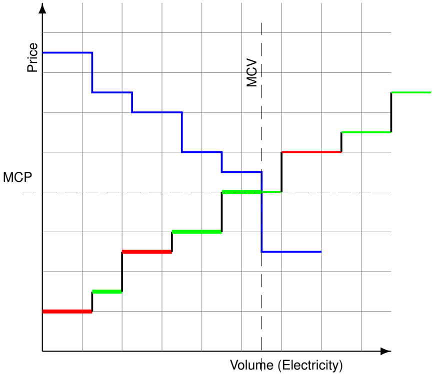


Hour 1

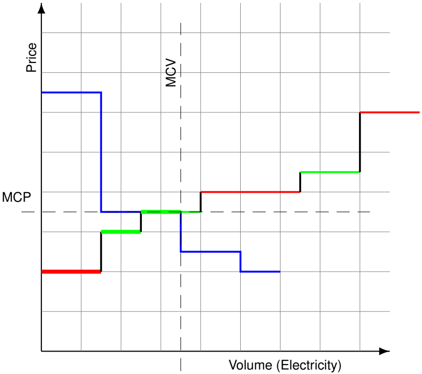


Hour 2

Market Equilibrium: Graphical Visualization

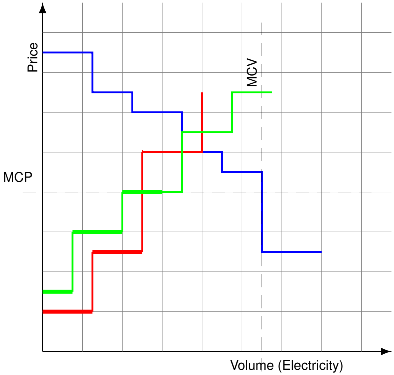


Hour 1

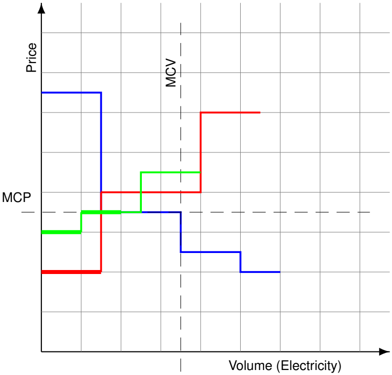


Hour 2

Market Equilibrium: Graphical Visualization

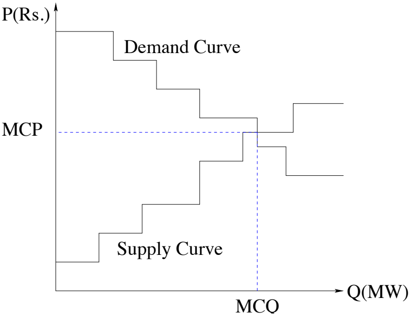


Hour 1

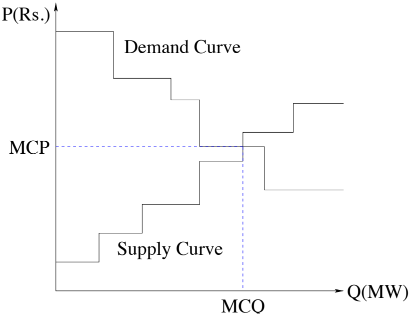


Hour 2

Different Possible Intersections

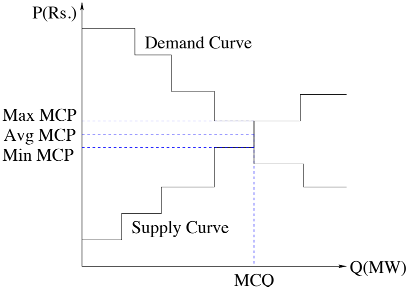


(a) Case 1: Single equilibrium point

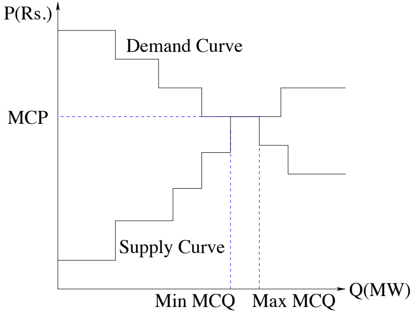


(b) Case 2: Single equilibrium point

Different Possible Intersections (cont.)



(c) Case 3: Multiple MCP



(d) Case 4: Multiple MCQ

Piecewise Linear Curves

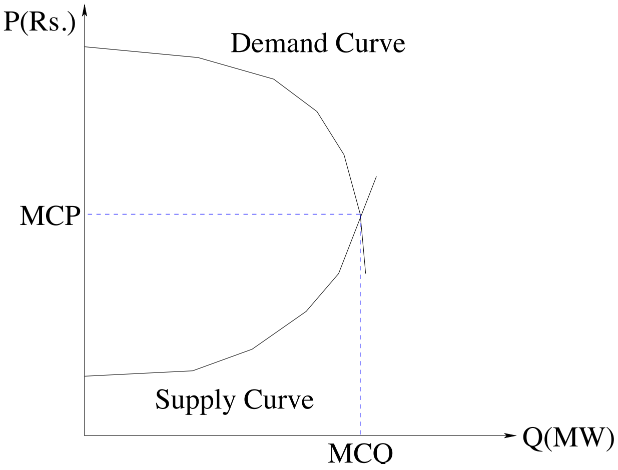
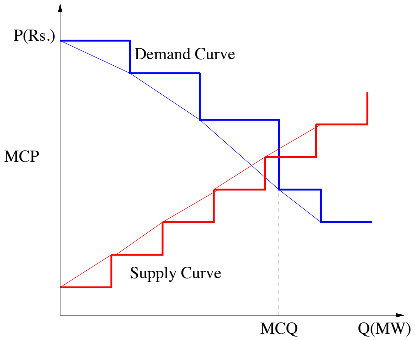


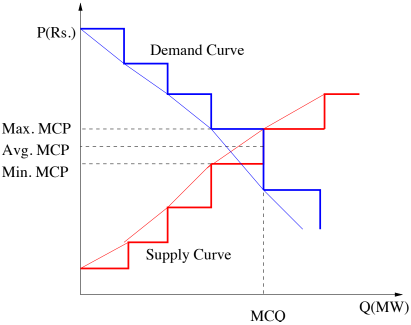
Figure: Piecewise linear curve

Social Welfare in Stepwise and Piecewise Linear Curves

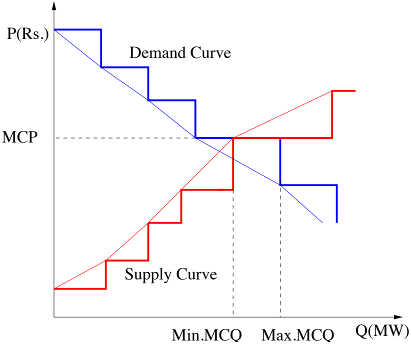


(a) Case1: Single equilibrium point (b) Case2: Single equilibrium point

Social Welfare in Stepwise and Piecewise Linear Curves (cont.)



(c) Case3: Multiple MCP



(d) Case4: Multiple MCQ

Clearing as Optimization Problem

Hourly Bids

- Each hourly market can be solved independently
- Simple linear programming (LP) framework suffices
- Objective is to maximize social welfare
- Subject to following constraints
  - Any bid to be scheduled within its limit
  - Supply matches demand

Clearing as Optimization Problem (cont.)

Hourly Bids

To formulate mathematically, we first introduce following notations for each j^{th} sell bid from i^{th} supplier

- $\mathbf{V}^{\max}_{\mathbf{s}(\mathbf{i},\mathbf{j})}$ as maximum power that can be supplied
- $\mathbf{p}^{\mathbf{step}}_{\mathbf{s}(\mathbf{i},\mathbf{j})}$ as bid price
- $V^{\mathrm{sch}}_{s(i,j)}$ as power scheduled to be supplied

Similar notations are introduced for demand bids

Clearing as Optimization Problem (cont.)

Hourly Bids

Finally, we have following LP problem to solve

$$
\begin{aligned}
\max \quad & \sum_{\langle i,j\rangle \in \mathcal{D}_h^H} V_{b(i,j)}^{\text{sch}} \mathbf{p}_{\mathbf{b(i,j)}}^{\mathbf{step}} - \sum_{\langle i,j\rangle \in \mathcal{S}_h^H} V_{s(i,j)}^{\text{sch}} \mathbf{p}_{\mathbf{s(i,j)}}^{\mathbf{step}} \\
s.t. \quad & 0 \leq V_{s(i,j)}^{\text{sch}} \leq \mathbf{V}_{\mathbf{s(i,j)}}^{\text{max}} \quad \forall \langle \text{i,j} \rangle \in \mathcal{S}_h^H \\
& 0 \leq V_{b(i,j)}^{\text{sch}} \leq \mathbf{V}_{\mathbf{b(i,j)}}^{\text{max}} \quad \forall \langle i,j \rangle \in \mathcal{D}_h^H \\
& \sum_{\langle i,j\rangle \in \mathcal{D}_h^H} V_{b(i,j)}^{\text{sch}} = \sum_{\langle i,j\rangle \in \mathcal{S}_h^H} V_{s(i,j)}^{\text{sch}}
\end{aligned}
$$

Note: Network is not modeled in the above formulation.

Lagrangian Function for Hourly Bid Matching

$$\mathcal{L}(V^{\text{sch}}_{b(i,j)}, V^{\text{sch}}_{s(i,j)}, \lambda_h, \overline{\mu}_h, \underline{\mu}_h) = -\left(\sum_{\langle i,j\rangle \in \mathcal{D}^H_h} \mathbf{p}^{\textbf{step}}_{\mathbf{b(i,j)}} V^{\text{sch}}_{b(i,j)} - \sum_{\langle i,j\rangle \in \mathcal{S}^H_h} \mathbf{p}^{\textbf{step}}_{\mathbf{s(i,j)}} V^{\text{sch}}_{s(i,j)}\right)$$
$$+ \lambda_h \left(\sum_{\langle i,j\rangle \in \mathcal{D}^H_h} V^{\text{sch}}_{b(i,j)} - \sum_{\langle i,j\rangle \in \mathcal{S}^H_h} V^{\text{sch}}_{s(i,j)}\right)$$
$$+ \overline{\mu}^{b(i,j)}_h (V^{\text{sch}}_{b(i,j)} - \mathbf{V}^{\text{max}}_{\mathbf{b(i,j)}}) - \underline{\mu}^{b(i,j)}_h V^{\text{sch}}_{b(i,j)}$$
$$+ \overline{\mu}^{s(i,j)}_h (V^{\text{sch}}_{s(i,j)} - \mathbf{V}^{\text{max}}_{\mathbf{s(i,j)}}) - \underline{\mu}^{s(i,j)}_h V^{\text{sch}}_{s(i,j)}$$

Lagrangian Function for Hourly Bid Matching

Set gradient of the above Lagrangian function zero

$$\nabla \mathcal{L}(V^{\text{sch}}_{b(i,j)}, V^{\text{sch}}_{s(i,j)}, \lambda_h, \overline{\mu}_h, \underline{\mu}_h) = 0$$

$$\Rightarrow \frac{\partial \mathcal{L}}{\partial V^{\text{sch}}_{b(i,j)}} = -\mathbf{p}^{\mathbf{step}}_{\mathbf{b(i,j)}} + \lambda_h + \overline{\mu}^{b(i,j)}_h - \underline{\mu}^{b(i,j)}_h = 0$$

$$\text{and} \frac{\partial \mathcal{L}}{\partial V^{\text{sch}}_{s(i,j)}} = \mathbf{p}^{\mathbf{step}}_{\mathbf{s(i,j)}} - \lambda_h + \overline{\mu}^{s(i,j)}_h - \underline{\mu}^{s(i,j)}_h = 0$$

- For a bid with no schedule, $\overline{\mu}^{b(i,j)}_h = 0$ and hence, $\lambda_h \geq P_{dj}$
- For a bid with complete schedule, $\underline{\mu}^{b(i,j)}_h = 0$ and hence, $\lambda_h \leq P_{dj}$
- For a bid with partial schedule, $\underline{\mu_j} = \overline{\mu_j} = 0$ and hence, $\lambda_h = P_{dj}$

Lagrangian Function for Hourly Bid Matching

Set gradient of the above Lagrangian function zero

$$\nabla \mathcal{L}(V^{\text{sch}}_{b(i,j)}, V^{\text{sch}}_{s(i,j)}, \lambda_h, \overline{\mu}_h, \underline{\mu}_h) = 0$$

$$\Rightarrow \frac{\partial \mathcal{L}}{\partial V^{\text{sch}}_{b(i,j)}} = -\mathbf{p}^{\textbf{step}}_{\mathbf{b(i,j)}} + \lambda_h + \overline{\mu}_h^{b(i,j)} - \underline{\mu}_h^{b(i,j)} = 0$$

$$\text{and} \frac{\partial \mathcal{L}}{\partial V^{\text{sch}}_{s(i,j)}} = \mathbf{p}^{\textbf{step}}_{\mathbf{s(i,j)}} - \lambda_h + \overline{\mu}_h^{s(i,j)} - \underline{\mu}_h^{s(i,j)} = 0$$

- For a bid with no schedule, $\overline{\mu}_h^{b(i,j)} = 0$ and hence, $\lambda_h \geq P_{dj}$
- For a bid with complete schedule, $\underline{\mu}_h^{b(i,j)} = 0$ and hence, $\lambda_h \leq P_{dj}$
- For a bid with partial schedule, $\underline{\mu_j} = \overline{\mu_j} = 0$ and hence, $\lambda_h = P_{dj}$

λ_h is MCP for h^{th} hour

Market Splitting

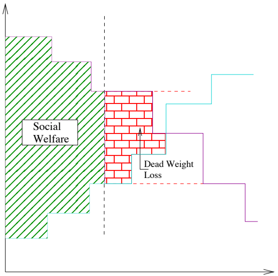


Figure: Social welfare and Dead weight loss in case of inter-regional congestion

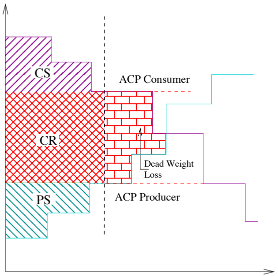


Figure: Congestion Rent

An Example of Market Splitting

Price	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0	5.5	6.0
						North						
Demand	7500	6500	6000	4500	4000	3600	3100	2700	2200	1800	1500	1000
Supply	0	0	1000	1800	2000	2600	2800	3000	3200	3200	3300	3400
						West						
Demand	8000	7000	6000	5500	4500	4200	3800	3500	3000	2500	2000	1500
Supply	0	0	1200	1500	1800	1900	1900	2000	2100	2100	2400	2400
						South						
Demand	3000	2800	2500	2500	2400	2200	2000	1500	1000	500	0	0
Supply	0	1000	1500	1600	1800	2000	2300	2300	2600	2800	2800	3000
						East						
Demand	2400	2400	2200	2000	1600	1400	900	500	0	0	0	0
Supply	0	2000	2400	2600	2800	3000	3400	3700	3800	4000	4500	4500
						North-East						
Demand	1300	1200	1000	600	400	100	0	0	0	0	0	0
Supply	0	2400	2800	3000	3500	3500	4000	4500	5000	5500	5500	5500

An Example of Market Splitting (cont.)

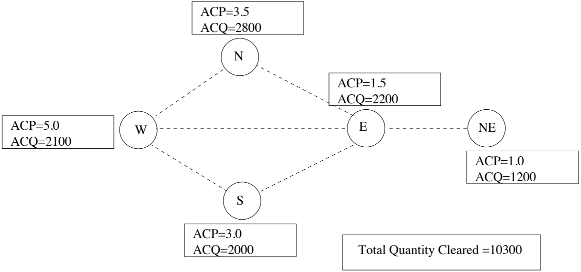


Figure: No inter-connection between zones

An Example of Market Splitting (cont.)

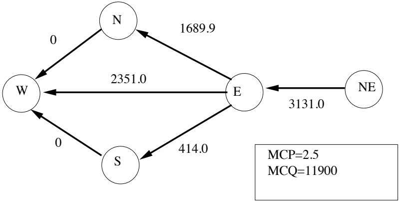


Figure: Flows with no capacity constraints on inter-connections

An Example of Market Splitting (cont.)

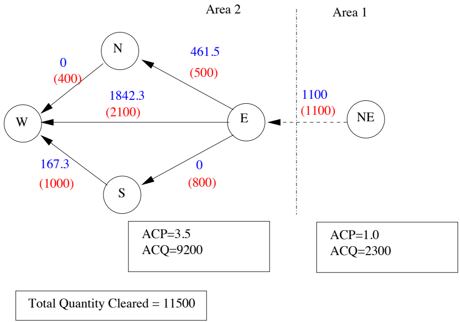


Figure: Market Splitting into two parts

Need of Block Bids

- Encourages participation of generators with high start-up and shut-down cost, typically thermal ones.
- Allows putting competitive price while recovering fixed cost

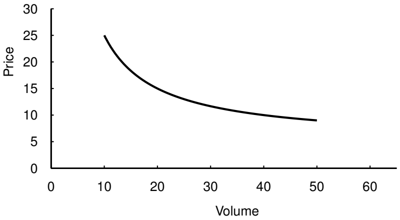
Example

- Consider a generator with cost of 5 per unit of power delivered
- Startup and shutdown cost of 200
- Can schedule maximum of 50 units of volume

Example (cont.)

No Block Bidding Facility:

- Full volume scheduled at least at price 9 to recover sunk cost
- Lower schedule of volume means even higher price



Example (cont.)

Block Bid to the Rescue:

- Bids for 4 contiguous hours
- Fixed cost recovery spread over multiple hours and large volume
- Bidding price becomes more competitive

$$\frac{200 + 4 \times 5 \times 50}{4 \times 50} = 6$$

Problems with Block Bids

- Discrete problem: Schedule full volume or none
- Consequently, scheduling becomes NP-Hard
  - Enumeration is the only known way to solve problem exactly.
- No equilibrium price may exist

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Non Existence of Equilibrium Price: An Example

Suppose following bids/offers are received:

1. Normal bid to buy power up to 100 units of power at price of 7 monetary units (MUs),
2. Normal offer to sell power up to 50 units of power at price of 3.5 MUs,
3. Normal offer to sell power up to 25 units of power at price of 4.0 MUs, and,
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$MCP > 7$ No buyer, while all sellers willing to supply

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$4.5 < MCP \leq 7$ All offers have to be scheduled

- Total supply of 125
- Maximum possible consumption of 100

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$MCP = 4.5$ Total demand of 100 to be scheduled, supply can be either 75 or 125

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MCP < 4.5 Buy order for 100 units of power will have to be scheduled, while supply will be below or equal to 75

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Hence, no equilibrium price can be declared.

Introducing Notion of PRB as Solution

- Market has to be cleared
- Some bids will have to be forced out of the market
- Bids rejected even after being competitive in terms of price are termed as *Paradoxically Rejected Bids (PRBs)*
- Which all bids to be rejected?

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Example of PRB

We revisit earlier example:

Social welfare maximization: Complete selection of buy bid. Hourly offer and block bid at 50 units each. MCP anywhere between 4.5 to 7. Hourly offer at lower price rejected. Social welfare of 300.

+ No hourly bids as PRBs: Schedule hourly bid at 75 units along with both hourly offers. Traded volume of 75 units and social welfare of 250. MCP at 7 MU.

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Solution Approach: Enumeration

- Considers all possibilities with block bids and solve scheduling problem for each case
- One with maximum welfare is the solution
- With n block bids, we have 2^n scenarios
- As for example with three block bids we have 8 possibilities: $[0, 0, 0]$, $[0, 0, 1]$, $[0, 1, 0]$, $[0, 1, 1]$, $[1, 0, 0]$, $[1, 0, 1]$, $[1, 1, 0]$ and $[1, 1, 1]$
- For 10 block bids 1024 scenarios
- With 20, we have 1048576 cases
- Clearly Impractical!!

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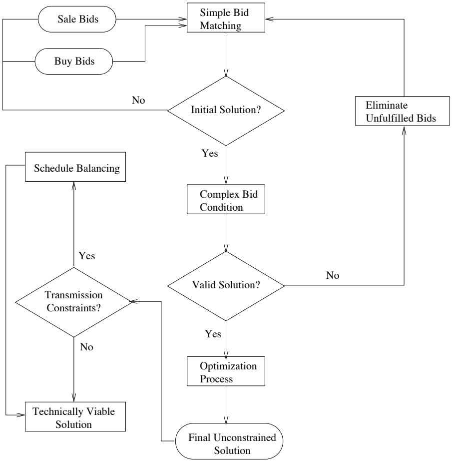
Solution Approach: Heuristic

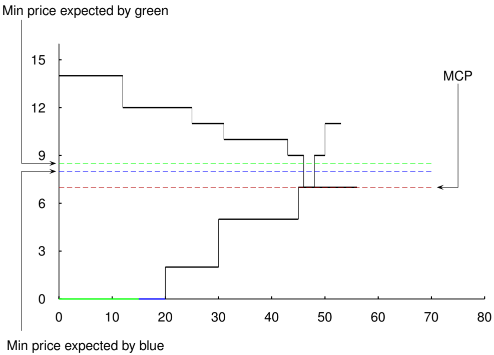
- Follows greedy approach
- Will have either of the following two characteristics
  - Computation time is practically feasible and solution generally not far away from optimal
  - Optimal solution is computed in small time for *most* of the cases; for few cases it may take forever
- Designing good heuristic is a challenge
- Incorporating new condition may lead to development of heuristic from scratch

Example of Heuristic



Source: *R. Madlener* and *M. Kaufmann* 'Power exchange spot market trading in Europe: Theoretical consideration and empirical evidence.' Technical report, OSCOGEN, Mar 2002.

How Heuristic May Fail



- With block bids placed at zero price, derived MCP shows that green block bid is worst off
- Hence, removed by heuristic and new MCP is computed, which shows blue in profit and thus, heuristic terminates
- However, more efficient solution is the one with green being scheduled

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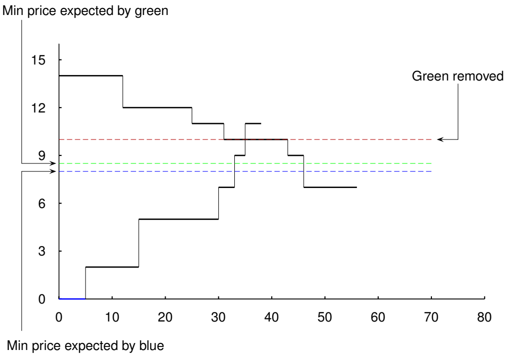

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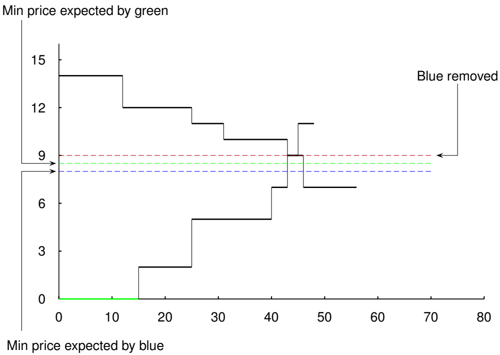

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MILP Approach

- Class of optimization problem with
  - Linear constraints
  - Linear objective
  - Some of the variables integral
- While LP can be solved polynomially, MILP is NP-Hard!!
- Researchers, world wide, have been working on solution techniques on MILP for last few decades
- Consequently, current state of art mature enough to handle few thousand variables for most of the cases
- On mapping scheduling problem to MILP, we can take advantage of these readily available algorithms
- Accounting new bid structures will require adding corresponding mathematical relations
- Network constraints can be very easily modelled

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Conclusions

- Market clearing mechanism with only hourly bids presented
  - Existence of market equilibrium and its relation with Lagrangian multipliers established
- Resulting complexities due to block bids highlighted
- Notion of paradoxical rejection introduced
- Scheduling techniques in presence of block bids discussed
- MILP framework needed to handle block bids

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Thank You

This is the post-print version of this article: Meeus, L., Verhaegen, K., Belmans, R., 2009. Block order restrictions in combinatorial electric energy auctions. European Journal of Operational Research, 196(3), pp. 1202-1206.

Block Order Restrictions in Combinatorial Electric Energy Auctions

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Abstract

In Europe, the auctions organized by "power exchanges" one day ahead of delivery are multi-unit, double-sided, uniformly priced combinatorial auctions. Generators, retailers, large consumers and traders participate at the demand as well as at the supply side, depending or whether they are short or long in electric energy. Because generators face nonconvex costs, in particular startup costs and minimum run levels, the exchanges allow "block orders" that are all-or-nothing orders of a given amount of electric energy in multiple consecutive hours, while the standard order consists of an amount for a single hour that can be curtailed. All exchanges restrict the size (MWh/h), the type (span in terms of hours) or the number (per participant per day) of blocks that can be introduced. This paper discusses the rationale of block order restrictions. Based on simulations with representative scenarios, it is argued that the restrictions could be relaxed, which some exchanges have already started doing.

Keywords OR in energy, E-commerce, Combinatorial Auctions/bidding, Pricing, Integer programming

1. Introduction

In Europe, the auctions organized by "power exchanges" one day ahead of delivery are an increasingly important part of the wholesale market (Meeus et al., 2005). Although participation is voluntary and the average traded volume is only about 10% of consumption, the hourly auction price is an important reference price for all contract negotiations. Generators, retailers, large consumers and traders increasingly participate at the demand as well as at the supply side, depending or whether they are long or short in electric energy.

The orders that can be introduced at these auctions are for the delivery or off-take of electric energy during an hour of the next day. The exchanges also allow "block orders" that are all-or-nothing orders of a given amount of electric energy in multiple consecutive hours. An auction with block orders can therefore be called a combinatorial auction. Combinatorial auctions have in common that orders can be placed on combinations of heterogeneous

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items, called packages or bundles, rather than just on individual items. An inspiring and comprehensive work on this topic is the book edited by Cramton, Shoham and Steinberg (2005). Combinatorial auctions have recently been employed in a variety of industries. De Vries and Vohra (2003) provide a comprehensive survey.

The advantage of combinatorial auctions is that participants can more fully express their preferences, such as complementarities between heterogeneous items. In electricity markets, there are complementarities between deliveries of electric energy in consecutive periods, for instance because of start-up costs of power plants. Block orders can indeed be seen as a combination of hourly orders. Blocks allow participants to provide an average price for a combination of hours. On average generators can offer cheaper prices for delivery in multiple consecutive hours as this allows them to spread out the start-up cost.

Both exchanges and participants consider blocks as important. On some exchanges up to 20% of total traded volume consists of block orders. Still, all exchanges restrict the size (MWh/h), the type (span in terms of hours) or the number (per participant per day) of blocks that can be introduced. This paper therefore analyses the rationale of block order restrictions.

Limiting the allowable combinations is known to be effective in reducing computational complexity (Pekec and Rothkopf, 2003; Park and Rothkopf, 2005). This and other reasons to restrict the use of block orders on exchanges are investigated by solving to optimality representative scenarios, based on the historical aggregated order curves of APX, to which sets of block order are added with various degrees of restrictions.

Section 2 explains how the representative scenarios have been constructed. Section 3 introduces the model that is used for the simulations. It therefore also introduces the auction optimization problem with blocks and the pricing approach applied by exchanges to clear their markets. Section 4 then discusses the effect of restrictions, based on the simulation results. Section 5 finally evaluates the restrictions imposed by exchanges.

2. Representative scenarios

The power exchanges with blocks are APX (Netherlands), Belpex (Belgium), Borzen (Slovenia), EEX (Germany), EXAA (Austria), Nord Pool (Norway, Sweden, Denmark and Finland) and Powernext (France). As illustrated in Table 1, the kind of blocks that can be introduced to these exchanges differ substantially.

Table 1: Block order restrictions on APX, Belpex, Powernext and EEX

	Nr block types	Max nr blocks / day / participant	Max size (MWh/h)
APX	354[1]	50	50
Powernext	10	INF[2]	100[3]
EEX	11	6	250

1 All combinations of consecutive periods are allowed
2 Per portfolio it is possible to submit every type once, but participants can submit several portfolios
3 Before 2005 it was 50 MWh

Powernext for instance does not restrict the number of block orders that can be submitted per participant per day, while the size is for instance more restricted on APX (50MWh/h) than on EEX (250MWh/h). On APX, any combination of consecutive hours is allowed so that 354 types of block orders can be traded. Powernext and EEX on the other hand restrict blocks to 10 or 11 types. Table 2

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illustrates the 10 block types that can be traded on Powernext.

Table 2: Block products on Powernext

Contract name	Time interval
Block Bid 1-4	00.00h – 04.00h
Block Bid 5-8	04.00h – 08.00h
Block Bid 9-12	08.00h – 12.00h
Block Bid 13-16	12.00h – 16.00h
Block Bid 17-20	16.00h -20.00h
Block Bid 21-24	20.00h – 24.00h
Block Bid 1-24	00.00h – 24.00h
Block Bid 9-20	08.00h – 20.00h
Block Bid 1-6	00.00h – 06.00h
Block Bid 1-8	00.00h – 08.00h

The scenarios used in this paper are based on the historical aggregated order curves of the Dutch power exchange APX. Their order curves are publicly available, which is not the case for most other exchanges. The 19 days illustrated in Table 3 have been randomly selected. APX launched their day-ahead auction in 1999 and its liquidity has since steadily increased as can be seen from the table.

Table 3: Days used for scenarios

Date (DD/MM/YY)	Average price (€/MWh)	Maximum price (€/MWh)	Total traded volume (MWh)
15/01/03	32	108	32636
27/03/03	30	41	31240
20/05/03	33	91	32874
04/07/03	33	100	27691
22/11/03	36	96	34102
22/02/04	20	26	34474
19/04/04	29	41	35864
15/06/04	35	70	31357
18/08/04	31	44	35279
21/10/04	32	42	38886
10/12/04	36	75	46350
29/01/05	33	44	50146
10/02/05	36	45	42239
25/03/05	39	60	46373
03/04/05	26	50	40843
07/05/05	32	42	42964
25/05/05	43	80	35119
26/06/05	31	46	47448
20/07/05	45	63	47792

These days are from different years, seasons, week-weekend. The hourly orders are extracted from these curves. Every scenario includes the hourly orders of one of these days. To simulate the effect of adding blocks to these representative days, sets of blocks are generated with various degrees of restrictions as follows:

- To study the effect of a type restriction, in half of all scenarios blocks can be of any type, as on APX, while in the other half, block are restricted to the 10 types found on Powernext (Table 2). Note that the Powernext types have been chosen because they are most restrictive.
- To study the effect of a size restriction, every scenario has a maximum block size between 10 and 300MWh/h. The blocks in a scenario can therefore have different sizes, but all are smaller than the determined scenario size limit. Note that the size limit considered in the analysis is higher than the largest allowed blocks of 250MWh/h on EEX. Blocks larger than 300MWh/h are not considered because such large capacity plants are base load and typically scheduled outside the exchanges.
- To study the effect of an number restriction, the number of blocks in a scenario ranges between 0 and 200. Note that if 200 blocks would be submitted, their share in total traded volume in the scenarios would be larger as it currently is on the exchanges. As mentioned in the introduction,

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blocks are said to represent up to 20% on some exchanges. Given an average block size of 150MWh/h, 200 blocks correspond to 30000MWh/h. For a block that on average spans 8 hours (1/3 of a day), this corresponds to a total volume of 1000MWh/day, which is up to 35% of the total traded volume on the days used to construct scenarios (Table 3).

Additionally, the following assumptions in line with what can observed on exchanges, have been made:

- Blocks are as likely to be introduced at the demand and supply side
- Blocks are price-setting orders, meaning that their prices are significantly different from zero and close to the market prices. Their price limits have been generated so that they deviate less than 10%, from the average price of the day (Table 3).
- The maximum admissible order price limit (Pmax) is 2500€/MWh, as on APX. Note that this is not intended to be a price cap but rather to protect against human error.

A batch of 200 scenarios has been created in the manner explained above. The results are presented in Section 4. Increasing the batch size to 200 has proved to be sufficient to present results that are not batch specific. The next Section explains how the scenarios are solved to optimality.

3. Auction optimization problem with blocks

Combinatorial auctions are typically difficult to solve optimization problems (Xia et al., 2005). This is also the case for the auction problem with blocks. The all-or-nothing constraint of block orders means that binary variables are necessary to model the auction problem. Models with binary variables for blocks and constrained continuous variables for hourly orders are Mixed Integer Linear Problems (MILP), which are difficult to solve.

With,

- hourly orders characterized by the hour (h) in which they are introduced, whether they are supply (i) or demand (j) and by a price (€/MWh) and quantity (MWh) limit (P_h , Q_h) ;
- block orders characterized by the hours included in the block ($h \in H$), whether they are supply (k) or demand (l) and by an average price (€/MWh) and quantity (MWh/h) limit (P , Q);
- nH the number of hours included in a block;
- block orders having a binary variable to implement the all-or-nothing constraint (b =1 if block is accepted; b =0 otherwise);
- block orders having a quantity limit for every hour to simplify the notation, which is zero for the hours not included in the block ($Q_h = 0$ if $h \notin H$);
- the accepted order quantities (q_{ih} , q_{jh} , q_{kh} , q_{lh}) as the decision variables;

The auction optimization problem with blocks is as follows: maximize total gains from trade (or trade efficiency),

$$Max \sum_h \left(\sum_j q_{jh} P_{jh} + \sum_l q_{lh} P_{lh} - \sum_i q_{ih} P_{ih} - \sum_k q_{kh} P_{kh} \right) \quad (1)$$

subject to market clearing constraints, equalizing demand and supply in every hour:

$$\forall h : \sum_i q_{ih} + \sum_k q_{kh} = \sum_j q_{jh} + \sum_l q_{lh} \quad (2)$$

and the order constraints:

$$q_{ih} \le Q_{ih} \quad (3)$$

$$q_{jh} \le Q_{jh} \quad (4)$$

$$q_{kh} = b_k Q_{kh} \quad (5)$$

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$$q_{lh} = b_l Q_{lh} \quad (6)$$

Combinatorial auctions are non-convex. This means that linear market clearing prices do not necessarily exist (see for instance Scarf, 1994 and Elmaghraby, 2004). If there are no hourly prices at which demand equals supply, one possibility is to resort to nonlinear pricing (see O'Neill et al., 2005 for a discussion on how shadow prices can be used to implement nonlinear pricing). Nonlinear pricing means that the optimal solution to (1)-(6) in terms of traded volumes (q, MWh) would be settled at hourly prices (p, €/MWh) in combination with a side payment (A, €) which can be different for all orders, i.e. resulting in a "pq + A" settlement.

Exchanges in Europe however have in common that they do not use side payments to clear their day-ahead auction markets (A=0). Instead, they equalize demand and supply at hourly prices by rejecting blocks that should be accepted looking at the hourly prices, i.e. Paradoxically Rejected Blocks (PRB). Note that blocks are however only accepted when they should be and hourly orders are cleared (accepted and rejected) completely in accordance with the hourly prices. To get the optimal solution with the above characteristics, the following constraints including the hourly prices (p_h) need to be added to the auction problem (1)-(6):

First, if a supply block is accepted ($b_k = 1$), the average market price should be at least as high as the price limit of the block, with nH the number of hours included in a block:

$$\forall k : b_k nH_k P_k \leq \sum_{k \in H_k} p_k \quad (7)$$

Equally, if a demand block is accepted ($b_l = 1$), the average market price should not be higher than the price limit of the block, with $P_{\max}$ the maximum admissible price for an order:

$$\forall l : \sum_{l \in H_l} p_h \leq nH_l (P_l + P_{\max}(1 - b_l)) \quad (8)$$

Second, if an hourly supply order or offer is accepted ($b_{ih} = 1$), the hourly price (p_h) needs to be at least as high as the price limit of the offer (P_{ih}), with b_h a binary variable equal to one if the hourly order is accepted:

$$\forall i, h : b_{ih} P_{ih} \leq p_h \quad (9)$$

Equally, if an hourly demand order or bid is accepted ($b_{jh} = 1$), the hourly price (p_h) cannot be higher than the price limit of the bid (P_{jh}):

$$\forall j, h : p_h \leq P_{jh} + P_{\max}(1 - b_{jh}) \quad (10)$$

Third, partially rejected or curtailed hourly orders should set the price. Therefore, if an offer is partially rejected ($b_{ih} = d_{ih} = 1$) or completely ($b_{ih} = d_{ih} = 0$), the hourly price cannot be higher than the price limit of the offer, with d_h a binary variable equal to one if the hourly order is partially rejected:

$$\forall i, h : p_h \leq P_{ih} + P_{\max}(b_{ih} - d_{ih}) \quad (11)$$

Equally, if a bid is partially rejected ($b_{jh} = d_{jh} = 1$) or completely ($b_{jh} = d_{jh} = 0$), the hourly price needs to be at least as high as the price limit of the bid:

$$\forall j, h : P_{jh} - P_{\max}(b_{jh} - d_{jh}) \leq p_h \quad (12)$$

All exchanges impose linear prices, which means that every day they solve the optimization problem (1)-(12). If they would drop constraints (7)-(12), they would increase gains from trade (and avoid PRBs), but trade would have to be settled by using side-payments.

As mentioned earlier, exchanges have however chosen to avoid the complexities of a settlement with side payments. Simplicity can indeed be considered as

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an important design feature of the exchanges in their role of fine tuning market of which the reference price is more important than the volume they clear directly.

4. Effect of block order restrictions

A batch of 200 scenarios has been solved to optimality according to the MILP model (1)-(12) on a Pentium® IV, using the CPLEX v11.0® solver software called from Matlab® using the Tomlab® interface.

In two scenarios, the optimal solution was not yet found after 2.5 days so that the solver was stopped. For all other scenarios, the solver calculation time is 4 minutes on average. The minimum and maximum calculation time is respectively a few seconds and 3.5 hours. 50% of the scenarios solve in less than one minute and 95% less than 10 minutes. This is typical for the performance of commercial MILP solvers.

The optimal solution to the MILP model (1)-(12) yields 4.15 PRBs per day on average, with a maximum of 27 in a day. In total, there are 829 PRBs for 19619 blocks in these scenarios. Therefore, the likelihood of blocks to be paradoxically rejected is only 4.36%. It is important to note that almost 40% of these PRBs are actually not loosing any money, i.e. their price limit is equal to the average market price, but other blocks loose up to 18€/MWh/h.

In the remainder of this Section, the effects of restricting the use of blocks on calculation time, the number of PRBs and trade efficiency are considered based on the simulation results.

4.1 Calculation time

Pekec and Rothkopf (2003) discuss non-computational approaches to mitigating computational problems in combinatorial auctions. Limiting the combinations participants are allowed to bid is described as an effective way to reduce the computational complexity of combinatorial auctions. Park and Rothkopf (2005) even propose an auction with bidder-determined allowable combinations.

Also in combinatorial electric energy auctions this is true. As discussed in the Section 2, in 50% of the scenarios every combination of consecutive hours is allowed, while in the other 50% of scenarios only have the 10 combinations that are allowed at Powernext. The difference in calculation time between these scenarios is illustrated in Figure 1.

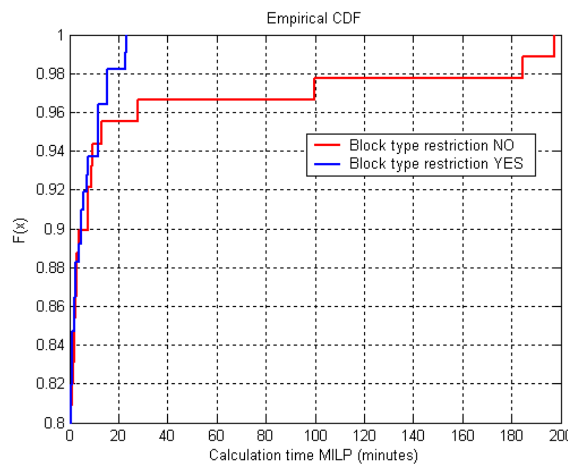

Figure 1: Calculation time MILP model (1)-(12) in minutes with and without a block type restriction

As illustrated in the figure, the group of scenarios in which the allowed combinations or block types are not restricted has more extreme outliers. Indeed, also the two scenarios not indicated in the figure that were stopped after 2.5 days of calculation are scenarios without a type restriction.

Significant coherence between calculation time and the number or size of blocks in the scenarios could not be found. One could expect a correlation between the number of blocks and the solver calculation time, as the number of blocks increases the problem size in terms of binary decision variables, but

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such a correlation could not be found. The correlation in the batch of 200 scenarios is only 0.041 and not significant. This can be partly explained by the fact that binary variables are also assigned to hourly orders and the number of hourly orders differs more between scenarios than the number of blocks.

Note that if linear prices are not imposed on the clearing, the calculation time significantly reduces to 0.6 seconds on average with a maximum of 1.4 seconds. This clearly indicates that the most significant computational complexity comes from constraints (7)-(12) and the binary variables that need to be assigned to the hourly orders to implement these constraints and therefore not from the number of blocks.

4.2 Paradoxically Rejected Blocks (PRB)

On average 4.36% of the blocks are paradoxically rejected. This indicates that it is not that big of an issue for the auction participants, which has been confirmed by talking to traders. Still, this paragraph will respectively consider whether block type, size and number restrictions are an effective way of reducing the number or likelihood of PRBs.

Table 4 compares the PRBs of the scenarios with and without a type restriction. There is no significant difference in the number of PRBs between these categories of scenarios. The null hypothesis that the means are equal, assuming a normal distribution for both samples and equal standard deviations cannot be rejected for a 5% significance (p-value is 0.1585).

Table 4: Effect block type restriction on PRB

Nr PRB	All types	Powernext types
Mean	3.6	4.5
Standard deviation	3.6	5.2

From the combinatorial nature of blocks, it can be expected that small blocks are less likely to become paradoxically rejected. Indeed, for instance only 1% of blocks smaller than 50MWh/h are paradoxically rejected, which is four time less than the average for blocks. However, as indicated in Table 5, there is no significant correlation between the likelihood of PRB and the maximum block size. Such a correlation would appear if all blocks in the scenarios are taken equal to the maximum block size, but what these results indicate is the presence of large blocks does not increase the likelihood that small blocks are paradoxically rejected.

It can also be expected that the number of PRBs increases with the number of blocks. The results in Table 5 confirm this, but also indicate that the increase is more or less proportional, as there is no significant correlation between the likelihood of PRB and the number of blocks in a scenario.

Table 5: Linear effect size and number of blocks on PRB throughout the whole range of that data

Correlations (linear regression R^2)	Nr blocks	Maximum block size
Nr PRB	0.6407 (41.4%)	0.3053 (9.3%)
Likelihood PRB (Illustrated in Figure 2)	-0.0362 (0.13%)	0.2139 (4.6%)
Likelihood PRB blocks < 50MWH/h	0.103 (1%)	0.181 (2.2%)

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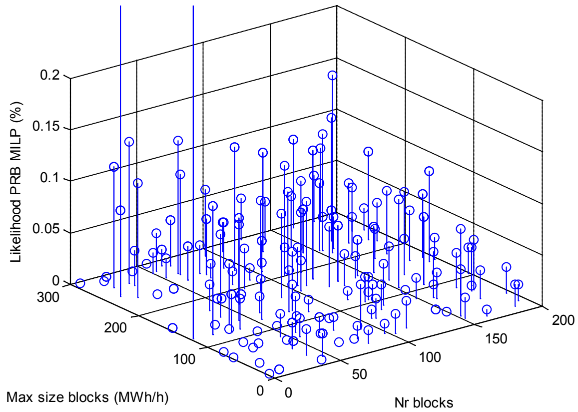

Figure 2: Likelihood PRB in MILP model (1)-(12)

4.3 Trade efficiency

The value of the objective function (1) is largely driven by the hourly orders because there are many price taking hourly orders. This does not mean that power exchanges should simply stop using block orders and thereby avoid the complexity of dealing with them. On the contrary, blocks are important for market parties and represent up to 20% of traded volume on the exchanges.

This does however explain why restricting the number, size or types does not have a statistically significant effect on the total gains from trade. This also explains why imposing linear prices only results in a loss of .0.05% in terms of gains from trade.

Note that the lost value is linked to paradoxically rejected blocks and can therefore be avoided by applying nonlinear pricing. However, this would also mean that side payments would have to be made. Applying the nonlinear pricing approach introduced in O'Neill et al. (2005) to the 200 scenarios, would for instance mean that 317393€ side payments need to be made in total. This is almost 9 times more than the total gains from trade that can be won by making these side payments. Note that only blocks would receive side payments, the average payment being 502€.

5. Evaluation of restrictions

From the previous section can be concluded that a block type restriction is an interesting option to consider. The results indicate that a type restriction has a clear effect on the solver calculation time and reducing this time can be of interest to exchanges that typically have only between 15 and 30 minutes to clear their day-ahead auctions. A type restriction is also not necessarily binding for the auction participants as blocks are mainly introduced for base load, peak load, etc and the allowed combinations typically match these periods.

From the previous section could also be concluded that the number of blocks and their size should not be restricted. The simulations clearly indicate that these restrictions have no significant impact on calculation time, the likelihood of PRB or trade efficiency. Still, it can be explained why all exchanges have such restrictions. One possible explanation is that participants were not used to trade blocks under the linear pricing regime introduced by power exchanges, which has been introduced in this paper and which is very different from the pricing approaches in other combinatorial auctions, so that every PRB is a potential complaint for starting exchanges. Note however that restricting the use of blocks is an artificial way of reducing PRBs. The real solution would be to avoid PRBs by resorting to nonlinear pricing.

It is also sometimes said that the unrestricted use of blocks would increase price volatility. For immature or illiquid markets with a lack of hourly orders, the lumpiness of blocks can indeed be an issue for the formation of prices. The scenarios used in this

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paper are based on APX from 2003 to 2005, which is more than 4 years after the exchange started in 1999. The results indicate that for mature markets the impact on prices of adding blocks is limited. In other words, there are ways to explain why exchanges have introduced these restrictions, but as these markets have matured it is time for them to omit or at least relax them.

Note that the size restrictions are currently clearly binding for traders. Generation units are easily larger than 50 MW and even larger than 250 MW. Because blocks can be paradoxically rejected, submitting 5 blocks of 50 MWh/h is not the same as submitting a block of 250 MWh/h.

7. Conclusions

The simulation results presented in this paper argue against restricting the use of blocks in the day-ahead auctions organized by exchanges. It is in the benefit of exchanges and auction participants to omit or at least relax these restrictions. Some exchanges have already starting doing that. The French Powernext has for instance doubled the allowed block size from 50 to 100 MWh/h and more recently also allows more combinations of hours in a block order.

The simulations are based on representative scenarios using actual order data from the Dutch exchange APX. Block sets with various degrees of block restrictions are added to these scenarios to study the rationale of these restrictions. The results clearly argue against block size restrictions and also against restrictions on the number of blocks a participant can submit per day. Inline with existing combinatorial auction literature (Pekec and Rothkopf, 2003; Park and Rothkopf, 2005), the results however do confirm that limiting the allowable combinations that can be included in a block reduces the solver calculation time. This could therefore justify a block type restriction.

It has also been explained that order restrictions in general can be justified for starting or illiquid exchanges. For instance the Austrian exchange EXAA introduced blocks in 2003 after one year of operation when the market had somewhat matured. More recently also the Belgian exchange BELPEX started without blocks in 2006, but introduced them after a few months of operation.

Apart from providing guidelines to exchanges on how to deal with blocks, this paper also discusses their particular approach of imposing linear prices in a nonconvex auction. An interesting extension to this work could therefore be to consider this pricing approach for other combinatorial auction settings (see Xia et al. 2004 for an overview of pricing approaches in combinatorial auctions). Specifically towards power exchanges, this work could be extended by considering other combinatorial products. A block in itself is also a restricted product. The auction participants might for instance be interested to combine hours without having to offer the same amount of electric energy in every hour. Note that some exchanges have already started to introduce more flexible combinatorial products and other are looking into this issue.

Acknowledgements

The authors gratefully acknowledge the support and contributions received from APX, Belpex, Elia and Powernext. The authors also thank the anonymous referees and the editor for their comments. The analysis and conclusions are of course the sole responsibility of the authors.

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Market coupling and the importance of price coordination between power exchanges

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ARTICLE INFO

Article history:
Received 3 July 2007

Keywords:
Pricing
Electric market equilibrium
Operational research
Power system economics
Duality

ABSTRACT

In Europe, market coupling stands for a further integration of wholesale trading arrangements across country borders. More specifically, it refers to the implicit auctioning of cross-border physical transmission rights via the hourly auctions for electric energy organized by power exchanges (PEXs) one day ahead of delivery. It therefore implies that the PEXs can optimize the clearing of their day-ahead auctions. Due to verticals in the aggregated order curves, the optimal solution can be settled at different prices. In order for prices to give correct locational signals for network development, generation and consumption, price coordination between exchanges is necessary. The paper illustrates this issue, its relevance and discusses how to deal with it.

1. Introduction

In Europe, generators self-schedule and they do this by submitting a production program to the network operator. Which and when generators are turned on and run is the result of trading in several types of markets. Trading is mainly bilateral, but in most countries this is supplemented with auction trading organized by power exchanges (PEXs) one day ahead of delivery for every hour of the next day. The auctions are used by market parties to fine tune their portfolios, which for instance means that generators can be on the supply as well as demand side depending on whether they are long or short. The PEXs use simple rules to settle contracts one day ahead of delivery when it is not worth getting into time consuming bilateral negotiations. Additionally, the exchanges act as counter-party for all transactions. The traded volume on the PEXs is typically 10% of consumption.

While wholesale trading within countries is not constrained by the network, it is constrained at the borders where there are structural bottlenecks. The transmission system operators (TSOs) determine transfer capacities (so-called net transfer capacities) independently per border and before trading actually takes place. In other words, before it is known how flows will be distributed over the different interconnections and without taking the interdependencies of a meshed network into account. About 10% of consumption is currently traded across borders in Europe.

As discussed in [1], the European version of a flow gate approach is not the most efficient way of dealing with the scarce network resources. This is not about to change soon, but what is changing is how these capacities are allocated to market parties. Non-market-based allocation methods have largely been abolished and replaced by separate auctions per border. The auctions are organized by the TSOs and are typically for yearly, monthly and daily physical transmission rights.

Arbitrage between the various PEXs is therefore already possible but explicit, requiring the purchase of physical transmission rights on a contract path. Besides being constrained by the available border capacities, arbitrage is also constrained by the time lag between the closing of the different border and PEX auctions and the uncertainty that this brings, especially given the high price volatility. Several empirical studies that compare the prices of border capacity with the price difference between exchanges indeed indicate that arbitrage is currently inefficient (see for instance [2]).

Market coupling refers to the implicit auctioning of physical transmission rights via the hourly auctions organized by PEXs one day ahead of delivery. Nord Pool (Elspot) already does this for several years for the total available capacity on the internal borders of the Scandinavian countries. Since November 2006, the capacity available day-ahead on the internal borders of France, Belgium and the Netherlands that used to be auctioned in a separate market organized by the respective TSOs is now used by the exchanges to optimize the clearing of their day-ahead auctions. This so-called trilateral market coupling (TLC) initiative is expected to be extended to include more countries.

Market coupling implies that exchanges can optimize the clearing of the offers and bids for electric energy submitted to

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doi:10.1016/j.energy.2008.04.013

their day-ahead auctions. As such, total gains from trading are increased. Often quoted benefits are also reduced price volatility and increased liquidity as orders can be matched across borders. Due to verticals in the aggregated order curves, the optimal solution can, however, be settled at different prices. In order for prices to give correct locational signals for network development, generation and consumption, price coordination between exchanges is necessary.

Section 2 introduces the market coupling optimization problem. Section 3 introduces the widely accepted approach to settle trading with network constraints, i.e. locational marginal pricing (LMP). Section 4 then illustrates that locational marginal prices (LMPs) have important properties and that they are not always uniquely determined. Section 5 discusses price coordination between exchanges, including its relevance and how it is being dealt with in the TLC initiative.

2. Market coupling optimization problem

The market coupling optimization problem involves demand and supply orders of different exchanges that need to be matched in order to maximize the total gains from trading. This means that the cheapest supply orders are matched with the most willing to pay demand orders. The only complexity in comparison with a single exchange optimization problem is that these orders come from different exchanges which represent a different network location. The demand and supply volumes traded on the different exchanges do not have to be equal, as long as the traded volumes equalize in total and the resulting flows between locations are feasible given the limited available network capacity.

For the market coupling optimization problem, the topology and capacities of the simplified network that need to be taken into account are given as they are pre-determined by the involved TSOs. Given is also the volumes and prices of the orders that have been submitted. What needs to be determined is which orders are accepted at which hourly price for every exchange. The optimization problem can therefore be formulated as follows:

Maximize the value of demand minus the cost of supply:

$$\operatorname*{Max}_{q}\left(\sum_{z}\left(\sum_{j} q_{jz}P_{jz} - \sum_{i} q_{iz}P_{iz}\right)\right) \tag{1}$$

with P_{jz} is the price limit of demand side order j submitted to exchange z (or introduced at location z), P_{iz} is the price limit of supply side order i submitted to exchange z (or introduced at location z), q_{iz}, q_{jz} is the decision variable representing the accepted volume of the respective orders

Subject to the order constraints (2) and (3), making sure that the accepted volume is not higher than the volume limit of an order:

$$q_{iz} \leqslant Q_{iz} \tag{2}$$

$$q_{jz} \leqslant Q_{jz} \tag{3}$$

With Q_{jz} is the volume limit of demand side order j submitted to exchange z (or introduced at location z), Q_{iz} is the volume limit of supply side order i submitted to exchange z (or introduced at location z).

And subject to DC load flow network constraints (4) and (5), which are a simplification of the actual power flow equations as for instance discussed in [3]. Constraints (4) equalize the net injections with the off-takes at every location. Constraints (5) make sure that the flow is not higher than the available capacity between the locations:

$$\forall z: \sum_{i} q_{iz} - \sum_{x} q_{jz} - \sum_{x} B_{zx}(\theta_z - \theta_x) = 0 \tag{4}$$

$$\forall z, x \in Z: B_{zx}(\theta_z - \theta_x) \leqslant Cap_{zx} \tag{5}$$

with B_{zx} is the susceptance of the interconnector between zone z and x, θ_z is the voltage angle, Cap_{zx} is the capacity of the interconnector between z and x.

Note that in practice, the exchanges solve this optimization problem for every hour of the next day and the hours are interdependent because of so-called block orders [4]. For reasons of clarity, abstraction is made of block order in this paper.

3. Price properties

Locational marginal prices (LMPs) are the most obvious choice to settle the optimal solution to the market coupling optimization problem. It basically means that the orders of an exchange are settled at the price that corresponds to the shadow price of its market clearing constraint (4). LMPs have interesting properties. They for instance give efficient locational signals for network development, generation and consumption. LMP is also widely used; especially in the North American markets (see for instance [5]). Although a lot of literature is available discussing the properties of LMPs (see for instance [6]), much less is available on implementation issues of LMP. This paper discusses an implementation issue related to the verticals in the aggregated order curves of the exchanges that is relevant for the European context.

The properties of LMPs can be derived from the optimality conditions of the market coupling optimization problem (1)–(5) as has been done in [7] for the more generalized problem. This leads to the following equations that define the necessary relation between the LMPs and the shadow prices of (5), which correspond to the value of the interconnections:

$$\forall z, x: \sum_{x} B_{zx}[p_z - p_x + \mu_{zx} - \mu_{xz}] = 0 \tag{6}$$

with p_z is the LMP, or simply price corresponding to location z. Note that demand and supply orders of a single location or exchange are cleared at the same price. μ_{xz} is the value of the interconnector between x and z, in the direction x–z, which corresponds to the shadow price of (5). Therefore, this price is zero if constraint (5) is non-binding, which is the case when the interconnector is not fully used.

Note that LMPs are not always as intuitive as one might think. Based on simplified examples in non-meshed networks, these prices have sometimes been attributed properties that the approach cannot deliver. For a discussion of common misunderstandings, see for instance [7,8].

4. Freedom in prices

4.1. Price ranges

Consider three exchanges PX1, PX2 and PX3 to which the orders listed in Table 1 are submitted. Fig. 1 illustrates the implied aggregated order curves for the three exchanges separately and jointly. If the exchanges are not coupled they would have cleared a volume of, respectively, 100, 100 and 100 MW h at a price of 10, 25 and 90€/MW h. Total gains from trading in that case would have been 18,500€ ((PX1:) 100 MW h (90–10€/MW h)+(PX2:) 100 MW h (90–25€/MW h)+(PX3:) 100 MW h (90–50€/MW h)). If the exchanges would be coupled without binding network constraints,

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Table 1
Demand and supply orders introduced to PX 1 to 3

PX1	PX2	PX3
Demand orders (bids)		
100 MW h@ 90€/MW h	100 MW h@ 90€/MW h	200 MW h@ 90€/MW h
Supply orders (offers)		
300 MW h@ 10€/MW h	175 MW h@ 25€/MW h	100 MW h@ 50€/MW h

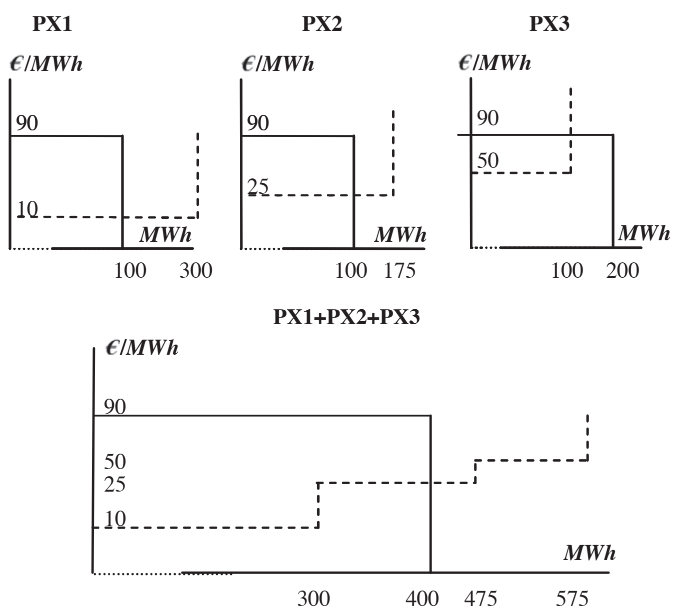

Fig. 1. Aggregated order curves of three PEXs separately and jointly.

they would have cleared a total volume of 400 MW h at a price of 25€/MW h. In comparison with the non-coupled situation, the volume traded in total has increased with 100 MW h and total gains from trading have gone up to 30,500€ (300 MW h (90–10€/MW h)+100 MW h (90–25€/MW h)). The difference, 12,000€, is because at PX3 more demand can be supplied (100 MW h (90–10€/MW h)) and additionally the more expensive supply offer at PX3 can be replaced with the cheaper supply offer introduced at PX1 (100 MW h (50–10€/MW h)).

The optimal solution implies a transfer of 200 MW h from PX1 to PX3, i.e. an injection in the network of 200 MW h at location 1 and a withdrawal of 200 MW h at location 2. Fig. 2 illustrates the possible locational prices and their corresponding export level. Note that these prices reflect the property of LMP that there is a single price per location to settle demand and supply at that location. Take for instance PX1:

- No supplier is offering at a price below 10€/MW h, while at such low prices demand will definitely want to be supplied fully, so that the corresponding import level for prices lower than 10€/MW h is 100 MW h.
- Demand does not want to pay more than 90€/MW h, while at such high prices supply will definitely want to be supplied fully, so that the corresponding export level for prices higher than 90€/MW h is 300 MW h.
- In between 10 and 90€/MW h demand wants to be fully supplied and suppliers want to supply all they offered as they can make a profit, so that the corresponding export level for prices between 10 and 90€/MW h is 200 MW h.
- If the price is 10€/MW h/90€/MW h supply/demand can be curtailed as the orders are marginally accepted at those prices, so that there are several corresponding import/export levels, as illustrated in Fig. 2.

In other words, an export of 200 MW h corresponds to several possible locational prices at PX1. As illustrated in Fig. 2, the same counts for PX3, which we will refer to as locational price ranges. Therefore, the LMP property of having a single price per location alone does not fix the prices in this illustration. Another LMP property is that if there are no binding network constraints, the network does not generate revenue. Fig. 3 illustrates the impact on the network of the transfer between PX1 and PX3. Note that it is assumed that all interconnector susceptances are equal so that 1/3 of the transfer goes via PX2 and 2/3 goes via the direct interconnection. Assuming that there is enough capacity to make this solution feasible, the remaining optimality conditions (6) translate into:

$$2p_1 - p_2 - p_3 = 0 \tag{7}$$

$$-p_1 + 2p_2 - p_3 = 0 \tag{8}$$

$$-p_1 - p_2 + 2p_3 = 0 \tag{9}$$

These equations basically imply that the locational prices have to be equal. Given that the price of PX2 is fixed at 25€/MW h (Fig. 2: there is no locational price range for PX2), this is the price for the three exchanges. In conclusion, an important LMP property is that LMPs are equal if there is no congestion in the network. Furthermore, in this example, there is only one set of prices that satisfies all LMP properties.

4.2. *Alternative sets of LMPs*

If we introduce binding network constraint to the example introduced in the previous section, the optimal solution changes. Fig. 4 illustrates this with a binding capacity constraint between PX1 and PX3. In this network, a transfer between PX2 and PX3 is more interesting than a transfer between PX1 and PX3, because the latter uses more of the scarce network resource (double the amount) which offsets the supply cost advantage PX1 (10€/MW h) has over PX2 (25€/MW h). In this network setting, the optimal solution is to transfer as much as possible between PX2 and PX3 and to use what remains on the interconnector between PX1 and PX3 for a transfer between these exchanges, as illustrated in Fig. 4.

Fig. 5 illustrates that the optimal solution yields two price ranges (PX2: $25<p<90$; PX3: $50<p<90$), but the export level of PX1 implies a price of 10. Given that there is a binding constraint between PX1 and PX3 so that μ_{13} is positive and given that p_1 is 10, (6) translates into:

$$20 - p_2 - p_3 + \mu_{13} = 0 \tag{10}$$

$$-10 + 2p_2 - p_3 = 0 \tag{11}$$

$$-10 - p_2 + 2p_3 - \mu_{13} = 0 \tag{12}$$

Eqs. (10)–(12) is a set of 2 two linear independent equations with three unknowns, meaning that there is some freedom in the prices. Indeed, solving the example in Matlab using the linprog solver yields prices of 10, 41 and 73€/MW h, respectively, for PX1, PX2 and PX3 and solving it with the CPLEX solver yields prices of 10, 30 and 50€/MW h (Table 2). In other words, the example clearly illustrates that prices can differ significantly depending on which software is used to solve the problem. If no additional

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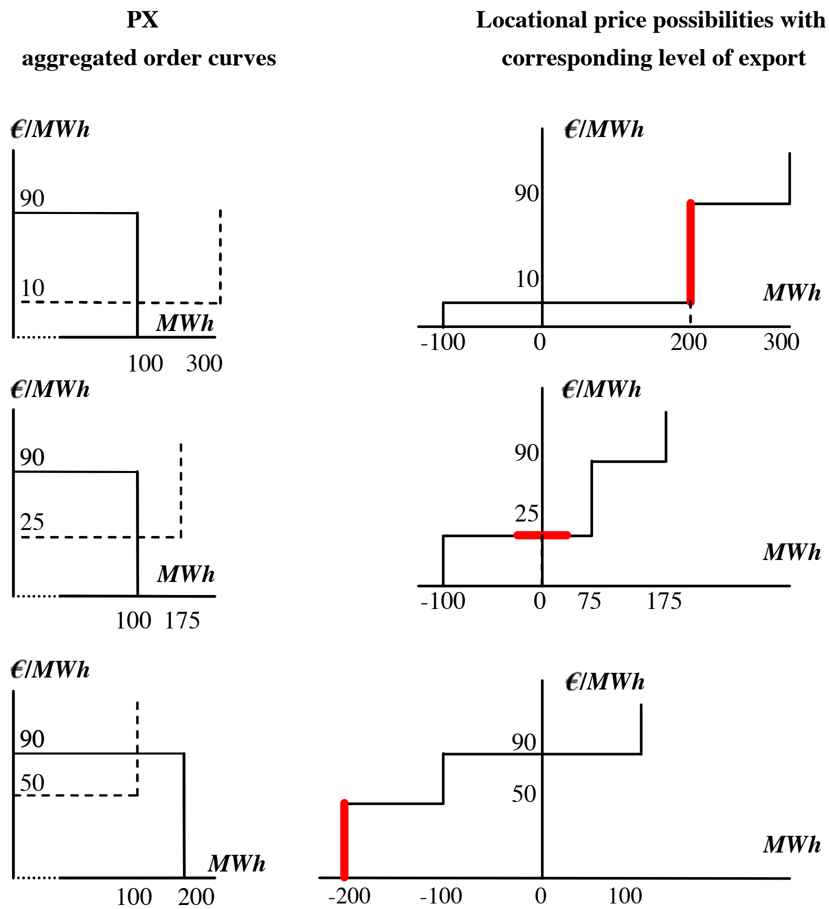

Fig. 2. Locational price ranges corresponding to the optimal solution reported in Fig. 1 as the intersection of aggregated order curves joined for the three exchanges.

method is applied to consciously choose between the alternative sets of LMPs, the solution will depend on the solver software that is used.

5. Price coordination

5.1. Importance of price coordination

Perhaps the simplest way of dealing with price ranges is to allow every exchange to independently choose which price they take of the possible prices that correspond with the optimal export level that comes out of the market coupling problem. The consequence would, however, be that even the most basic LMP property, which is that prices should be equal if there is no congestion, is not necessarily satisfied. Even though the most willing to pay demand would still be matched with the cheapest suppliers, the distribution of gains from trading would be different. In this case, the network could generate congestion rents, giving incentives to further invest in the network, while increasing the network capacity would not improve welfare. In other words, only LMPs give correct locational signals for network development, generation or consumption. Therefore, the best way to coordinate prices is to use the shadow prices of the market clearing constraint, which are the LMPs.

The remaining question is what to do in case there are alternative sets of LMPs. Consider the illustration from the previous section. Table 2 summarizes some of the possibilities to choose from. As indicated in the table, the value of the interconnector between PX1 and PX3 (μ_{13}) is always positive. This is because the interconnector between PX1 and PX3 is congested. The value of a congested interconnector (€/MW h) is equal to the congestion rents (€) divided by the flow over the interconnector (MW h). Congestion rents are the result of transfers between exchanges with different prices. In the illustration, prices in PX1 and PX2 are lower than in PX3 so that transferring energy from PX1 and PX2 to PX3 generates a revenue that is called congestion rent. In general, congestion rents can be expressed in function of the value of the interconnectors μ_{zx}:$z, x \in Z$, but also as a function of the LMPs p_z:$z \in Z$, which is equivalent:

$$\sum_z \sum_x B_{zx}(\theta_z - \theta_x) \cdot \mu_{zx} = \sum_z (\sum_j q_{jz}* - \sum_i q_{iz}*) \cdot p_z \qquad (13)$$

With $q_{iz}*$, $q_{jz}*$ is the optimal traded volumes, resulting from the solving the market coupling problem (1)–(5).

Note from Table 2 that the signal to invest in the network (μ_{13}) can be double as high in the illustration, depending on whether congestion rents are minimized or maximized when choosing between different sets of LMPs. The highest μ_{13} value is actually the negative effect on total gains from trading if the capacity would be reduced with 1 MW, while the lowest μ_{13} value is the positive effect on total gains from trading if the capacity would be increased with 1 MW:

- 1 MW more, is 3/2 MW h more transfer between PX1 and PX3, which would mean replacing 3/2 MW h of supply in PX3 at 50€/MW h with supply from PX1 at 10€/MW h, which is a gain of 60€ (3/2(50–10)).

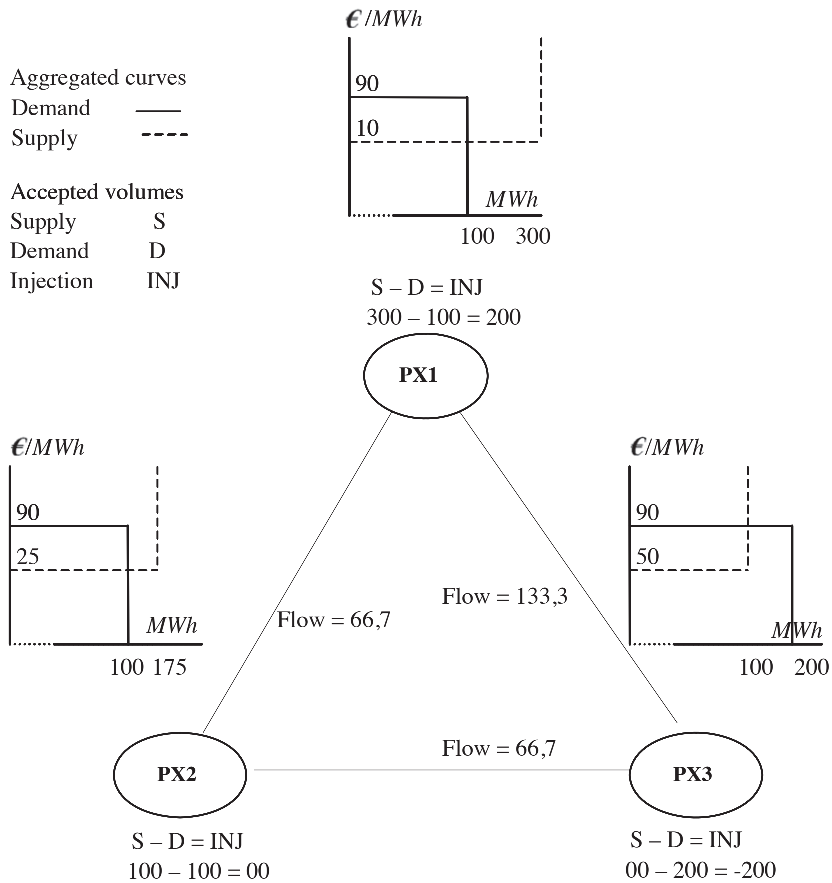

Fig. 3. Impact optimal solution (Fig. 1, intersection of aggregated order curves joined for the three exchanges) on the network.

- 1 MW less, is 3/2 MW h less transfer between PX1 and PX3, which would reduce by 3/2 MW h demand in PX3 with a value 90€/MW h and supply in PX1 at 10€/MW h which is a loss of 120€ (3/2(90–10)).

In principle, the highest and the lowest value are as relevant, but in a European context with scare interconnection capacity between countries, the question is rather which interconnector to further expand than which to maintain. This is one argument in favor of minimizing the congestion rents when choosing between sets of LMPs. Another argument is that one of the main concerns at the moment in Europe is that only a small fraction of the congestion rents is used to invest in the network.

It can therefore be concluded that a good and straightforward way to choose between alternative sets of LMPs is to minimize congestion rents.

5.2. *Minimizing congestion rents*

A general approach to determine LMPs would therefore be to first solve the market coupling problem (1)–(5). Once the optimal traded volumes ($q_{iz}*$, $q_{jz}*$) are known, also the price ranges are known for every exchange. The optimization problem can therefore be formulated as follows:

Minimize congestion rents:

$$\sum_z \left(\sum_j q^*_{jz} - \sum_i q^*_{iz} \right) \cdot p_z \qquad (14)$$

with p_z is the decision variable, representing the price corresponding to location z.

Subject to the price ranges and (6), which are the optimality conditions of the market coupling problem. If applied to the illustration from the previous section, solving this simple linear programming (LP) problem yields prices of 10, 30 and 50€/MW h for PX1, PX2 and PX3 (Table 2). Eqs. (10) or (12) than imply that the value of the interconnection between PX1 and PX3 is 60€/MW h, which is the value that corresponds to 1 MW capacity increase of that interconnection as discussed in the previous subsection. Note that if the market coupling problem has to deal with more constrained interconnectors as in the illustration, this only means that the above LP problem will contain more variables.

5.3. *Relevance of price coordination*

Which price is chosen on a price range is of course only relevant if coupled exchanges are often faced with such price ranges and if they are significant. Fig. 6 illustrates the price ranges on Belpex for the first 2 months of operation. In 30% of the hours observed there is no price range, and in 80% of the hours the price range is smaller than 20€/MW h. This implies that in 20% of the hours the price is larger than 20€/MW h. Note that there are even a few observations with price ranges peaking close to 400€/MW h, even though the figure stops at 160€/MW h. Given that a typical wholesale price is 50€/MW h, this is a very relevant part of the price formation on the PEXs.

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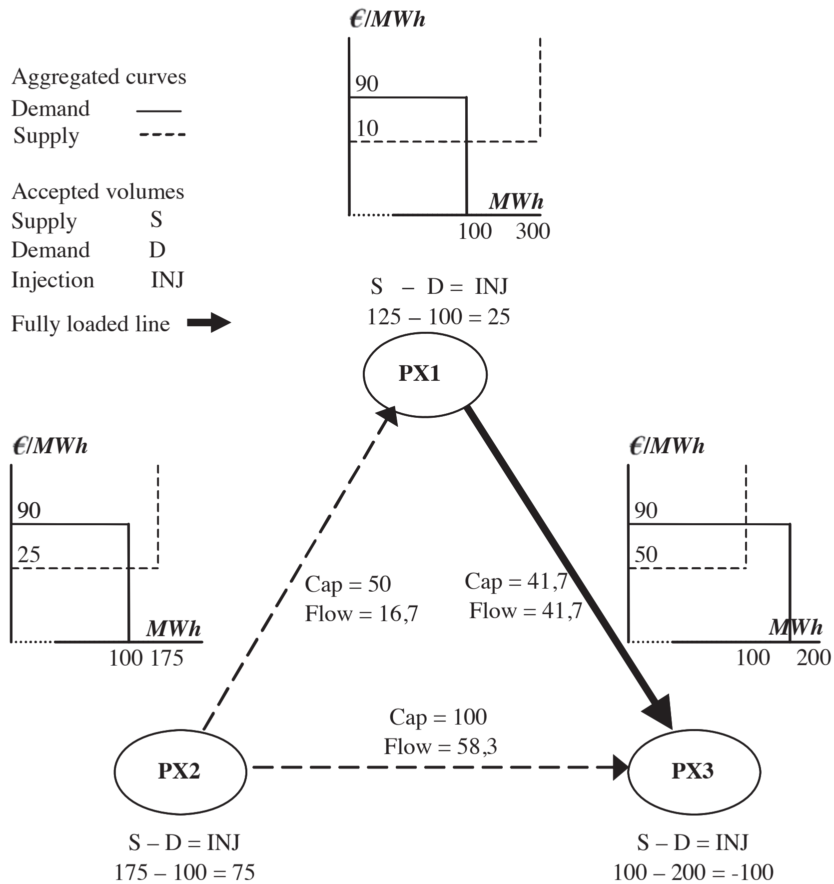

Fig. 4. Introducing price sets.

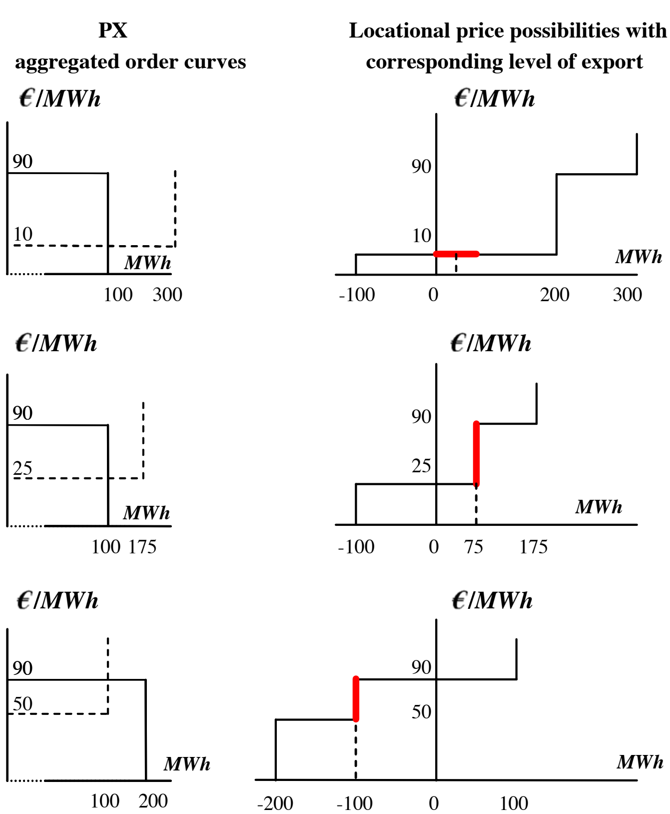

Fig. 5. Locational price ranges for solution in Fig. 4.

Table 2
Demand and supply orders introduced to PX 1 to 3

(€/MW h)	Linprog	CPLEX	Min CR	Max CR
PX1	10	10	10	10
PX2	41	30	30	50
PX3	73	50	50	90
μ_{13}	94	60	60	120

For the moment, the TLC initiative encompasses only France, Belgium and the Netherlands, which are aligned in that order. As the internal borders are not meshed, LMPs have more straightforward properties. For instance, the price of an interconnector is the difference between the location prices a both sides of the interconnector. Additionally the flow always goes from a high price region to the low price region, which is not necessarily the case if the network is meshed.

In [9], the price determination in case of price ranges is explained for TLC. The approach is specifically for three aligned markets. It is based on taking the middle price of an overlap between price ranges, subject to the LMP properties, which are called high level properties of the algorithm. If market coupling is extended to more markets and meshed networks, the approach discussed in this paper could be used, which is to minimize congestion rents, subject to the optimality conditions of the market coupling problem.

6. Conclusions

Market coupling means that exchanges optimize the clearing of the electric energy orders submitted to their day-ahead auctions. In

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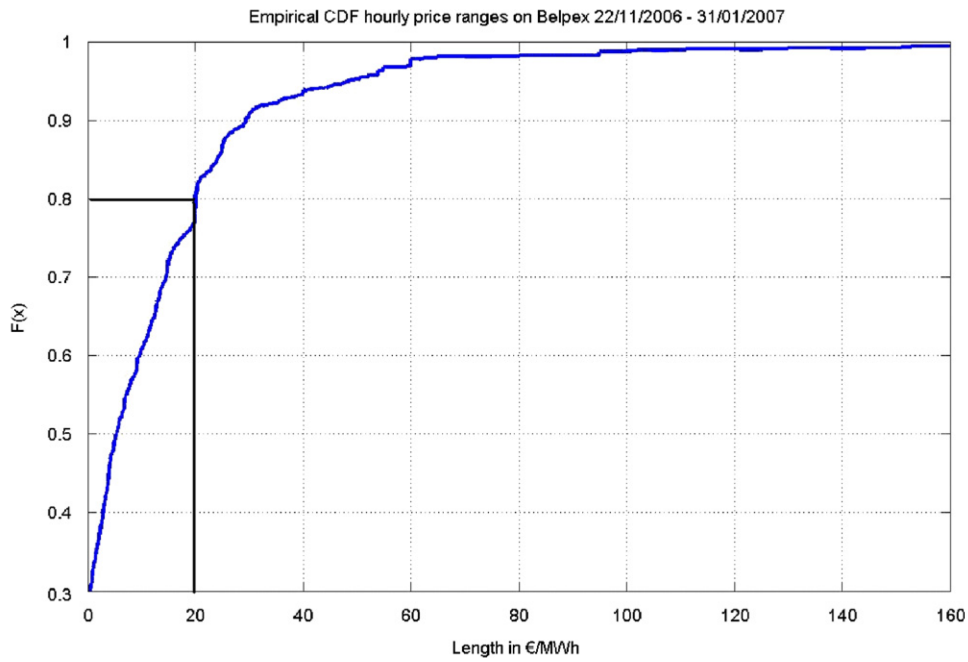

Fig. 6. Observations from Belpex.

doing so, orders introduced at different locations are exchanged to the extent that the available network capacities allow. Prices at these optimal exchange levels can be undetermined on an interval or price range due to the verticals in the aggregated order curves. For a single PEX, a simple rule such as taking the middle price of the possible prices is sufficient. For coupled exchanges, coordination is, however, necessary in order not to distort the locational incentives for network development, generation and consumption. Additionally, it has been discussed that LMPs can be derived from the optimality conditions of the market coupling optimization problem, but that these conditions do not necessarily uniquely determine the prices, in which case it has been discussed that the set of prices needs to be chosen that minimizes congestion revenues.

Acknowledgments

The authors thank the three anonymous referees and the editor for their valuable comments. The analysis and conclusions are of course the sole responsibility of the authors.

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OSCOGEN
Optimisation of Cogeneration Systems in a Competitive Market Environment

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Reinhard Madlener, Markus Kaufmann

Power exchange spot market trading in Europe: theoretical considerations and empirical evidence

OSCOGEN

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Contract No.
ENK5-CT-2000-00094

Project co-funded by the European Community under the 5th Framework Programme (1998-2002)

Contract No.
BBW 00.0627
Project co-funded by the Swiss Federal Agency for Education and Science

Contract No.
CEU-BS-1/2001
Project co-funded by Termoelektrarna toplarna Ljubljana, d.o.o.

March 2002

Abstract

This paper discusses exchange-based spot market trading of electricity in Western Europe, both from a theoretical and an empirical perspective. The theoretical section contains a selection of references to recent and seminal research in this field of research, and touches upon issues such as the dealing with grid constraints, modelling of bidding systems, bidding strategies, types of auctions, pricing and matching rules, types of spot markets, trading systems, and the main benefits and success factors of power exchanges. In the empirical part, it provides an overview of the main features and the functioning of the major existing (and planned) power exchanges in Europe (i.e. APX, Borzen, EEX, EXAA, GME, Nord Pool, OMEL, Powernext, UKPX, and APX UK). The article ends with a glossary of selected terms that are important in this field of research. The information contained should provide useful for the design of bidding tools that can be used by power-only and combined-heat-and-power (CHP) generating companies for generating bids in a liberalised power market environment.

JEL Classification Nos.: C62, C78, D44, D81, R32;

Keywords: electricity exchange, spot market trading, power pool auctioning, bidding system, CHP, OSCOGEN;

Table of Contents

1 Introduction

Over the last years and in the face of the ongoing liberalisation of the electricity sector in Europe and many other parts of the world, a number of electricity exchanges has been put into operation, and the development is far from completed. The main goal of exchange-based spot markets lies in the facilitation of the trading of short-term standardized products and the promotion of market information, competition, and liquidity. Power exchanges (ideally) also provide other benefits, such as a neutral marketplace, a neutral price reference, easy access, low transaction costs, a safe counterpart, and clearing and settlement service. Besides, spot market prices are an important reference both for over-the-counter (bilateral) trading, and for the trading of forward, future and option contracts.

In this paper, which mainly focuses on some theoretical considerations and a description of the most important exchange-based spot markets for electricity in Western Europe, we discuss various trading systems and related aspects. This will help to better understand how electricity generators can place their bids on the various power market exchanges, and helps in the design of bidding tools for the generation of optimal bids, and in the actual generation of bids, given certain production characteristics and a particular market structure and situation.

The organisation of the paper is as follows: Section 2 contains some theoretical considerations on the functioning and crucial aspects of bidding systems for electricity, and provides an overview on the most important literature in this field. Section 3 then describes the bidding mechanisms of the major (Western) European power exchange markets. Section 4 concludes. At the end of the paper, a glossary with a selection of important terms has been appended.

2 Theoretical Considerations

Competitive power markets are commonly organized around one or more auctions. Particularly, a market maker receives bids from generators and demand estimates or bids from power retailers and/or end-users, from which he/she calculates an optimal dispatch schedule – i.e. the production rule that minimizes the cost of meeting demand, subject to the technical and physical constraints imposed by the grid. Moreover, the price and dispatch schedule found constitutes a reference for other products, such as bilateral contracts, term products, financial contracts, physical options, and the like (Léautier, 2001). In order to enhance market transparency, typically a daily price index is published.

2.1 Bidding System Modelling

In the literature several approaches have been introduced to model the behaviour of generating firms that place bids in the power exchange market. Bolle (1992), Green and Newbery (1992), and Newbery (1998) have modelled the market by means of *supply-function equilibria*, i.e. the bids of a supplier are assumed to be continuously differentiable. In contrast, von der Fehr and Harbord (1993) and Brunekreeft (2001) have modelled the pool market by an *auction approach* that assumes a *step supply function*. The model of Brunekreeft, for example, provides theoretical arguments for several empirical observations. For example it reveals that with a decrease in the number of firms the bids of these firms increase unambiguously. Wolfram (1998) obtains corresponding empirical results.

2.2 Bidding Strategies

The actual bidding strategy chosen by an electricity generator will depend on a multitude of factors, such as market history, auction market rules, etc. The development of an appropriate bidding strategy requires, on the one hand, the simulation of the market and, on the other hand, a dynamic adaptation of the bidding strategy according to the changes in the market.

Supatgiat, Zhang, and Birge (2001) derived optimal bidding strategies for generators as a Nash equilibrium. They proved that in a deterministic demand case a pure strategy equilibrium point always exists. But with stochastic demand it is possible that no such point will result. They also show that the dispatch result may not be socially optimal when each bidder behaves optimally. Wolfram (1998) examined empirically the bidding behaviour in the case of the pool system in England and Wales and found evidence for several manifestations of strategic bidding. For example the mark-up over marginal costs in sale bids rises with the probability that the plant will be used.

2.3 Types of Auctions

A variety of auctions can be thought of to be used as allocation and pricing mechanisms for electric power. Table 1 depicts an example for a classification of auctions. One criterion is the number of bidding sides. If only price bids from one market side – normally the sellers – are accepted, the auction is called *one-sided*. In contrast, a *double-sided* auction uses bids from both the sellers and the buyers of the traded commodity. For the pricing rule there are also two general variants relevant. First, the *uniform pricing* provides the same price for every accepted bid. The price is set according to the price limit of the last accepted bid. Second, the transactions can be priced in a discriminatory manner (*pay-your-bid pricing*), with the price being the limit of the accepted bid in question (see section 2.6 below for details). [1] Auctions also differ in the way bids are handled, i.e. whether they are disclosed to all participants or not (*sealed vs. open auctions*).

Table 1. Classification of auction types (example)

Criteria	Type	
No. of bidding sides:	One-sided	Double-sided
Objective function:	Cost minimisation	Consumer payment minimisation
Pricing rule:	Uniform pricing	Discriminatory (pay-your-bid) pricing
Disclosure of bids:	Open	Sealed

Source: own illustration

In order to find an efficient mechanism various auction types have been studied. For example Hobbs et al. (2000) analysed a Vickrey-Clarke-Groves auction, which is a generalization of the Vickrey auction.[2] A special feature of this auction type is the payment determination, which is a function of the bid price for the amount of power accepted and of the increase in social welfare that results from accepting that bid. This feature motivates honest bidding even by participants with market power. The disadvantage of this type of auction is that it will frequently result in losses for the auctioneer. Elmaghraby and Oren (1999) compared auction structures differentiated according to the way the daily demand is partitioned in separate markets. Another way to classify auctions is according to their demand type. On the one hand, in *vertical auctions*, daily demand is split into hourly or half-hourly markets. *Horizontal auctions*, on the other hand, are characterised by a division of the demand into

[1] See Sheblé (1999): 19-20, 45.

[2] In a Vickrey auction or a second-price sealed-bid auction for an indivisible good, the buyer with the highest bid gets the good at the price corresponding to the second-highest bid.

different types – e.g. base, shoulder and peak demand – that are auctioned sequentially. They concluded that a horizontal auction is more efficient than a vertical auction.

The question of whether to use uniform or discriminatory pricing rules is addressed by Bower and Bunn (2001) and Madrigal and Quintana (2001), among others. In the model of Bower and Bunn the auction results in higher market prices when using the discriminatory pricing rule than with the uniform pricing rule, because of a significant informational advantage of large participants in a discriminatory auction. In contrast, Madrigal and Quintana propose a non-uniform pricing rule to avoid prices far above the competitive level. Denton, Rassenti, and Smith (2001) investigate the performance of an auction mechanism with *sealed bids* and a mechanism with *open displayed tentative market results* until the market is called, respectively. The former mechanism outperforms the latter one in a non-convex environment.[3] With sealed bids attempts to manipulate prices are more costly.

2.4 Dealing With Grid Constraints

Externalities arising from the transmission network can be seen as an 'unusual technical feature' inherent to the power system. Léautier (2001) for example shows that in the presence of transmission constraints power exchange auctions do not necessarily yield *ex post* production-efficient solutions.

Another question is the expansion of the grid. Boyer and Robert (1998) deal with the search for mechanisms to ensure efficient investment in the enlargement of the network. Proposed mechanisms include some form of *access pricing rule* that allows entrants to increase the grid capacity by using the infrastructures of incumbents and tradable transmission congestion contracts that reward investment in grid infrastructure.

2.5 Other Issues

There are various other issues concerning bidding-based trading systems for electricity. For example, the possibility of generators to exercise *market power* attracts considerable attention. Wolak (2000) and Green and Newbery (1992) addressed this issue for Australia and for England and Wales, respectively. Wolak suggested regulating the price by forcing a large enough quantity of hedge contracts on the generators to restrict the exercise of market power.

Geman (2001) discusses some features of *spot and derivatives prices*. Boisseleau (2001) is concerned about *competition* on a power exchange and about *competitiveness* of a power exchange. These two issues cannot be separated, as a minimal level of competition among the participants on an exchange is a condition for the competitiveness of this exchange.

Others analyse the *unit commitment problem*. Dekrajangpetch and Sheblé (1999) state that the *LaGrangian relaxation* based auction methods are biased in favour of the power suppliers.[4] They suggest that the unit commitment should be decentralized in order to allow the market operator to use auction methods that are not based on heuristic rules, like for example interior point linear programming. Madrigal and Quintana (2001) propose a non-uniform pricing scheme to select a schedule if no market equilibrium exists in the unit commitment problem.

[3] Non-convexity in this context refers to the avoidance of fixed cost penalties for generators in the case of operation below the minimum capacity and for wholesale buyers in the case of failure to serve their non-interruptible demand.
[4] Such an auction uses LaGrangian relaxation to find the solution to the unit commitment problem (see also Glossary, p. 28).

2.6 Markets

On a liberalised electricity market, the participants can act on a variety of markets.[5] Traditionally they can trade electricity bilaterally on the over-the-counter market (OTC), where the bulk of transactions is still being settled. Alternatively, in some countries organised markets (i.e. exchanges) have been established. These organised markets typically comprise one or more of the following markets.

2.6.1 Day-ahead market

Generally, exchanges provide at least a day-ahead market, where the bids are submitted and the market is cleared on the day before the actual dispatch. The day to be scheduled is divided into n periods of x minutes each. Each bidding firm makes a price bid for every generation unit for the whole day.

Commonly, in the day-ahead market either *hourly contracts* (for the 24 hours of the calendar day) or *block contracts* (i.e. a number of successive hours) are being traded. Whereas the former allows the market participants to balance their portfolio of physical contracts, the latter allows them to bring complete power plant capacities into the auction process. Block contract bidding may either be organised for a certain number of *standardised blocks* (dominant), or for *flexible blocks* (as has been introduced at the Amsterdam Power Exchange).

2.6.2 Intra-day/Adjustment/Hour-ahead market

Due to the long time span between the settling of contracts on the day-ahead market and physical delivery, exchanges sometimes offer an *intra-day market*, sometimes also referred to as *hour-ahead or adjustment market*. This market closes a few hours before delivery and enables the participants to improve their balance of physical contracts in the short term.

2.6.3 Balancing services/Real-time market

To balance power generation to load at any time during real-time operations, system operators use a balancing or real-time market. After the closure of the spot market, participants can submit bids that specify the prices they require (offer) to increase their generation or decrease their consumption (decrease their generation or increase their consumption) for a specific volume immediately. Such balancing services (also referred to as ancillary services), for which competitive market mechanisms are increasingly sought for, cover the provision of a number of services (e.g. voltage control, frequency response and reactive power support).

Some grid operators in Europe have started to procure the capacities and energy necessary to provide ancillary services from other companies via published auctions. This currently still fragmented market is expected to become increasingly integrated in the near future.[6] Therefore, especially the tertiary- and minute-reserve market could turn into a liquid wholesale market, as there are many power producers who are able to provide those services and to meet the existing substantial needs of both the grid operators and the suppliers in this direction. Furthermore, as there is no need to make additional investments in technical equipment, the market access barrier is small.

CHP plants could basically provide these services, too, given that sufficient capacity is being held in reserve for these purposes when optimising the unit commitment and/or dispatching. The authority responsible for the bidding at the market has – sometimes simultaneously – to find the best bidding strategy for electricity, reserve capacity, heat, and possibly fuel in order to maximize profits.

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[5] See Kraus and Turgoose (1999): 64-68.
[6] Personal communication with A. Hofmann/BEWAG; see also www.eon-net.com; www.rwenet.com .

On some markets, the reserve capacity is being cleared only after the clearance of the power market. In those cases it is quite likely that prices are being calculated at the marginal cost, as this is the last possibility to sell the available capacity. On the contrary, this situation seems quite unrealistic, as several power exchanges are in the process of building up intra-day trading markets. Therefore, plant operators will trade on fixed and variable costs in order to make the opportunity profits otherwise realized at the power exchange market.

2.7 Trading System

European exchanges normally provide *bidding-based trading* in contracts for power delivery during a particular hour of the next day (except in England and Wales, where half-hour contracts are traded). The usual trading system is a daily *double-sided auction* for every hour to match transactions at a single price and a fixed point in time. Again the UK is an exception, since trading only takes the form of *continuous trade*.

In either form participants determine, by submitting their bids, how much they are prepared to sell or buy at what prices. Sometimes the possible price values are bounded by a top limit (e.g. EEX in hourly auctions, Powernext). Another special feature to be aware of are limits to price volatility in order to achieve price continuity (e.g. EEX in continuous trading, Borzen). If the potential execution price lies outside these limits, participants are allowed to change their bids in an extended call phase of an auction or an auction is initiated in continuous trading to get a new reference price.

Usually the participants can add several execution conditions to their bids, and they can offer or ask the same quantity of power for a period of consecutive hours called *block bids*. All the submitted bids are collected in a sealed order book, i.e. the participants know only their own bids.

2.7.1 Auction trading

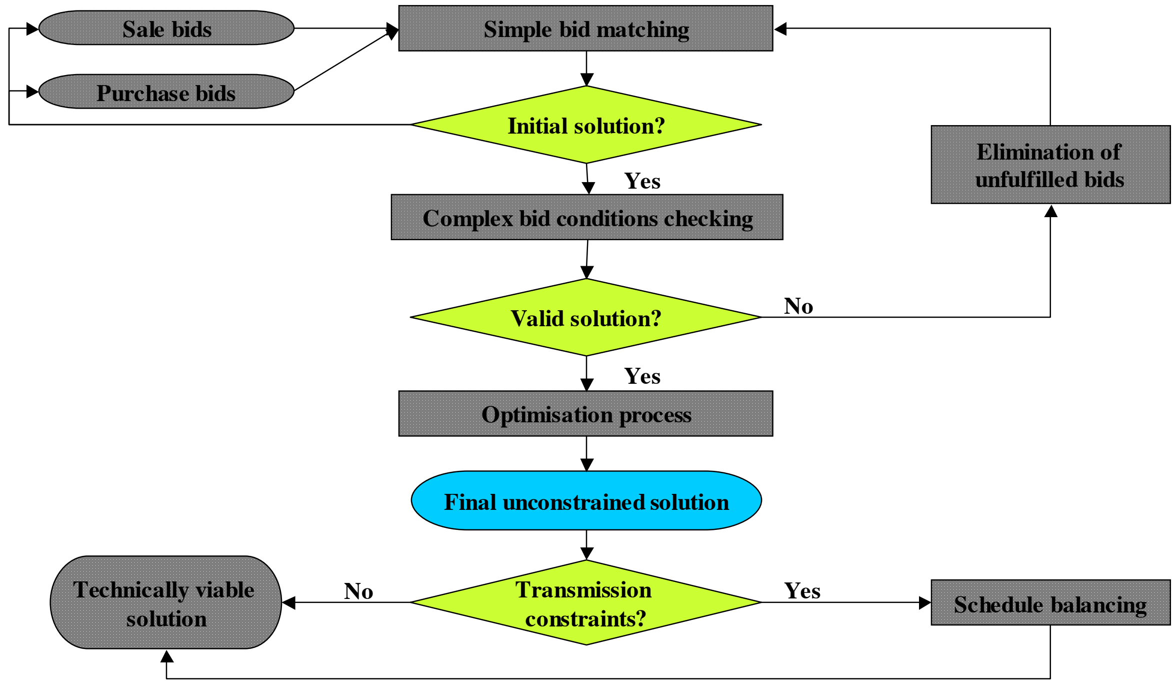
Figure 1 depicts the *basic structure of an auction*. Participants can submit and change their bids until the closure of the call phase. Changed bids get a new time designation, which may be important for the matching of bids (section 2.9). For *price determination* all the bids collected up to the predetermined closure of the call phase are sorted according to the price and aggregated to get a market demand and supply curve for every hour. Some exchanges include the block bids in the aggregation by changing the blocks into price-independent bids for the hours concerned (e.g. APX, EEX in hourly auctions, Nord Pool). Others use continuous trading to settle block contracts (section 2.8.2.).

The simple bid matching ignores any execution conditions or grid capacity constraints and results in an initial market clearing price, or *initial auction price*, for every hour and trade volumes for every bid (see Figure 2). The market clearing price is the price level at the intersection of the aggregated demand and supply curves. If there is no intersection of the two curves, there may be a second round of submitting bids in order to get an auction price or the last calculated market clearing price of the product in question – referred to as the reference price (see sections 2.8 and 2.9 below for more details).

The initial solution has first to be checked against all the *conditions added to the bid*. For block bids, an average of the market clearing prices for the hours included in the bid is calculated. This price has to be equal, or better, than the price limit stated by the participant to satisfy the bid (minimum income (sales) or maximum payment (purchases) condition).

If not all conditions are satisfied the initial solution is not valid. In this case one of the unfulfilled bids is eliminated and the price calculation is run again. This checking process is iterated until all the remaining bids can be fulfilled.

Figure 1. Basic structure of an auction



Source: own illustration

Sometimes the *valid solution* resulting of the bid conditions checking *is optimised* in a next step (such as at APX and OMEL). This process tries to minimise the amount of money that removed bids would earn if they were not removed.

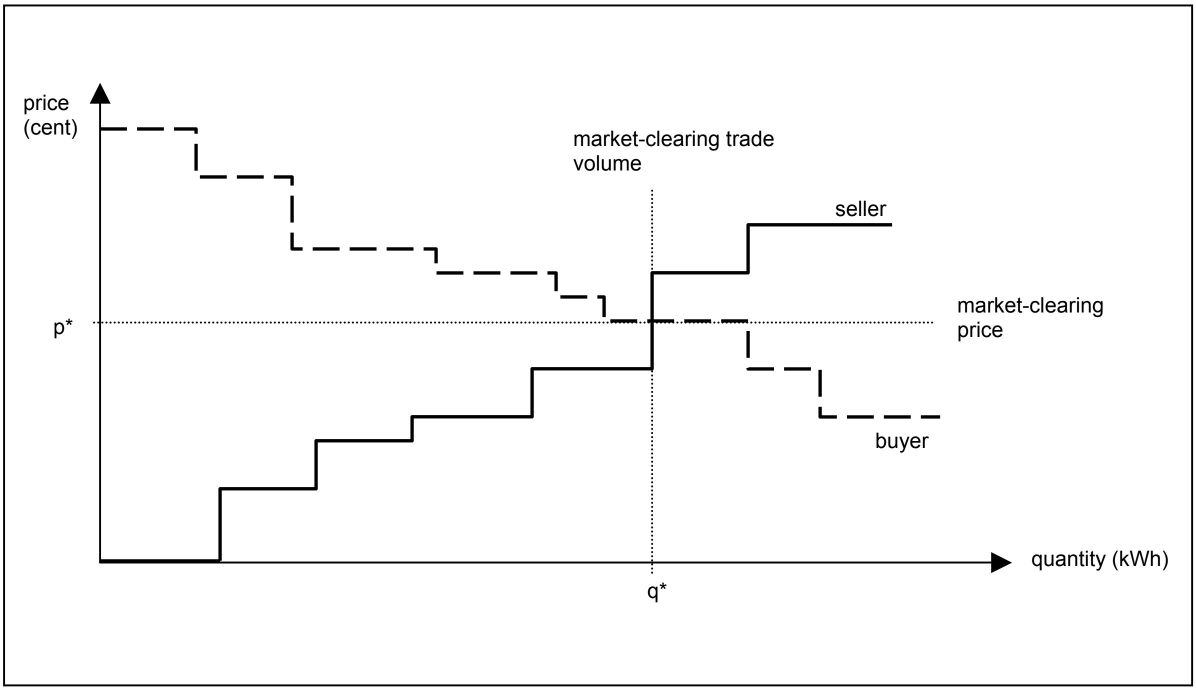
The trade volumes of the matched bids have also to be checked against the transmission grid capacities. If there are *transmission constraints*, the schedules have to be balanced to get a technically viable solution. *Schedule balancing* is done by only adjusting the trade volumes (like at OMEL), by adjusting the trade volumes and re-running the iterative bid matching (like at APX), or by splitting the market in several areas (like at EXAA, EEX, GME, Nord Pool). This takes place either before (APX) or after the optimisation (OMEL) process and results in a technically viable solution.

2.7.2 Continuous trading

Some exchanges provide an alternative trading form to the auction system called *continuous trading*. This form is used to either trade only block contracts (Borzen, EEX) or individual hours and block contracts (UKPX, APX UK).

Continuous trading differs from auctions in the following points. Firstly, participants have access to the order book. Secondly, each incoming bid is immediately checked and matched if possible according to price/time priority. Finally, the contract price is not the same for all transactions as it is determined according to only the concerned bids (pay-your-bid pricing at UKPX, APX UK) or the bid register at the time of the bid matching (Borzen, EEX). At some exchanges (Borzen, EEX) continuous trading is preceded by an opening auction and followed by a closing auction. Both auctions are similar to the auction described before.

Figure 2. Simple bid matching



Source: own illustration

2.8 Pricing Rules

2.8.1 Auction trading

In auctions the most common pricing rule is uniform pricing. The uniform price is the price level at the intersection of the aggregated demand and supply curves and is normally called the *market clearing price*. It provides a maximum trade volume. Because a simple aggregation of the bids results in discrete curves, there may not be a well-defined price solution. Exchanges handle this problem in two different ways. Some use linear interpolation instead of simple aggregation to get linear curves (EEX in hourly auctions, Powernext).[7] Others set up additional rules for price determination in case of multiple price levels at the intersection of the two curves.

Linear interpolation can be used at two different stages. For instance, EEX interpolates between the price values of every single bid, whereas Powernext interpolates between the highest price for which aggregated demand is greater than aggregated supply and the lowest price for which aggregated supply is greater than aggregated demand.

Rules for price determination in case of multiple price limits at the intersection of aggregated demand and supply curve differ also between the various exchanges. At APX the average of the purchase and the sale price limit at the intersection is chosen.[8] OMEL determines the market clearing price as the price of the last accepted sale bid that was accepted to meet the matched demand.[9]

In Austria (EXAA), in contrast, price determination is based on the so-called reference price, defined as the weighted average of the market clearing prices of the same product on the same weekday of the last three weeks:

[7] Information results from personal communication with T.Pilgram/LPX and from www.powernext.fr .
[8] See www.apx.nl/main.html .
[9] See www.omel.es .

- If the reference price lies *between the highest and lowest price limit*, the auction price is equivalent to the reference price;
- If the reference price is higher than the *highest price limit*, the auction price is determined according to this limit;
- If the reference price is lower than the *lowest price limit*, the auction price is determined according to this limit.[10]

To minimize the surplus for each price limit in the order book, EEX uses a still more sophisticated rule for the opening and closing auctions in continuous trading, namely one that is based on the surplus: if the surplus of all price limits is on the buy side (*demand surplus*), the auction price is stipulated according to the highest limit; in contrast, if the surplus of all price limits is on the sell side (supply surplus), the auction price is stipulated according to the lowest limit.[11] When there is a supply surplus for one part of the price limits and a demand surplus for another part, or when there is no surplus for any price limit, the reference price as the last price determined for an energy product is taken into account for the stipulation of the market clearing price (i.e. in the same way as at EXAA).

At Borzen the middle value of the possible values is taken as the market clearing price, provided it is equal or greater than the reference price. Otherwise, the reference price is taken for the settlement of the contracts.[12] The reference price is defined as the *market clearing price* achieved in the previous corresponding trading session (previous working day, previous non-working day, national or other holiday). The reference price is also used for the pricing of transactions when only bids without price limit are executable.

2.8.2 Continuous trading

In continuous trading there is no uniform price for all settled contracts. Contracts are either priced at the offered price of the bids in question (APX, UKPX, APX UK), or according to complex rules that take all the bids of the order book at the moment of matching into account.

The following rules apply for price determination in continuous trading at EEX (in addition to price/time priority; Borzen established similar rules):

- if an incoming bid encounters an order book where there are only bids with price limit on the opposite side of the book, the price is determined by the respective highest bid or lowest ask limit in the order book;
- if a bid without price limit is entered into an order book where there are only bids without price limit on the opposite side of the book, this bid is executed at the reference price and to the extent possible;
- in all other cases the incoming bid is executed against the bids without price limit, according to price/time priority, at the reference price or higher (at the highest limit of executable bids) in the event of unexecuted purchase bids, or at the reference price or lower (at the lowest limit of executable bids) in the event of unexecuted sale bids, respectively.

2.9 Matching Rules

2.9.1 Auction trading

In auctions all purchase bids with a price limit higher than the market clearing price and all the sale bids with a price limit lower than the market clearing price are executed. Just as for the case of price

[10] See www.exaa.at .
[11] Information results from personal communication with T. Pilgram/LPX, 4 June 2002.
[12] See www.borzen.si/en/about.htm .

determination the simple aggregation of the bids may not result in well-defined trade volume since supply and demand curves are discrete. Again different solutions to this problem exist.

Linear interpolation as mentioned with regard to price determination is one of these solutions. At EEX, for example, in the hourly auctions for every bid a volume can be assigned to every price. At Powernext, to give another example, the volume assigned to each participant will be calculated by linear interpolation between the two price/quantity combinations of the bid within which the market clearing price falls.

Other exchanges use rules for matching an eventual surplus instead of linear interpolation. In case of a demand (supply) surplus, APX and OMEL for instance distribute the offered (demanded) quantity at the market clearing price proportional to the volume of the purchase (sale) bids at this price limit. Another way is to state a matching priority according to the volume (bigger volumes come first) and/or the time designation of the bids (first come, first serve). This ensures that at maximum one bid is subject to only partial execution (Borzen, EEX in auctions around continuous trading, EXAA).

2.9.2 Continuous trading

Continuous bids are normally matched according to price acceptance of bids of the opposite side. At EEX, to give an example, incoming bids are checked against and matched with the bids in the order book to the possible extent according to price/time priority. Bids with no price limit have precedence over bids with a price limit and sale (purchase) bids with a lower (higher) price limit take precedence over bids with a higher (lower) limit. In the event of bids having the same limit, time applies as the second criterion. In this case, bids that were entered earlier have priority. Unexecuted bids, or parts of bids, are entered into the order book and sorted according to the price/time priority.

2.10 Services Provided and Success Factors of Power Exchanges

In this final subsection, we want to list some of the most important services (benefits) offered by, and the success factors of, power exchange markets.

A power exchange typically offers the following services:

- an automatic and in most cases Internet-based market interface;
- clearing & settlement of deals;
- counterpart risk taking;
- accounting and billing of the spot market and term-market products;
- various information needed, or asked for, by the market participants.

Success factors of an exchange can be measured by:

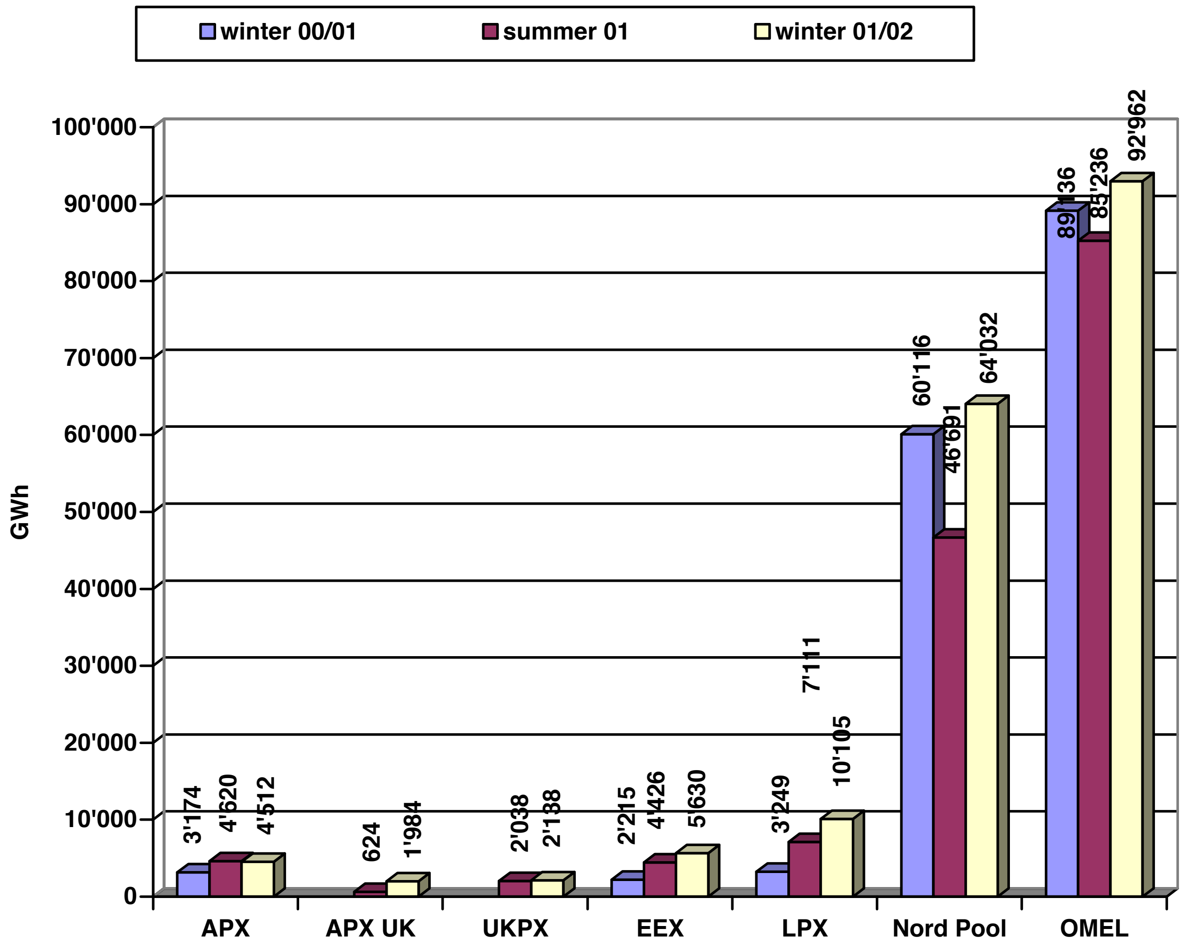
- number of market participants;
- liquidity of the market;
- (regional) growth of the market;
- competitiveness of the fee structure.

3 Empirical Evidence: Market Mechanisms and Bidding Systems at European Power Markets

In this section we provide an overview of the various bidding systems in place, or currently being planned, at the main Western European power markets (in alphabetical order: APX, Borzen, EEX/LPX, EXAA, GME, Nord Pool, OMEL, Powernext, and the triade UKPX/ APX UK/ UK IPE).

As an indication of the relevance of the various exchanges, total volumes traded on the spot market for the exchanges that have been in operation for at least a year are summarized in Figure 3. Particularly, the figures shown depict the turnover for six months (winter: October to March, summer: April to September) on the day-ahead market (except for APX UK and UKPX: hour-ahead market). Note also that the volume traded at OMEL is not directly comparable to the others because it is a mandatory pool.

Figure 3. Spot market volumes on European power exchanges



Source: CEPE, based on a similar illustration by Cap Gemini Ernst & Young (2002)

3.1 APX – Amsterdam Power Exchange (The Netherlands)

The Amsterdam Power Exchange comprises a *daily day-ahead spot market* (since May 1999) and, more recently, an *adjustment market* (since Feb 2001).[13] In 2001, on average some 9% of Dutch net electricity consumption were traded on the APX. By January 2002 altogether 36 international market players (generators, distributors, traders, industrial end-users) have been active on the APX.[14]

[13] See also www.apx.nl/products/main.html .
[14] For another assessment of APX see Boisseleau (2001).

3.1.1 *Day-ahead spot market*

The day-ahead spot market enables participants to buy and sell electricity for any of the 24 hours of a day one day in advance. Participants can also offer blocks, i.e. the same quantity of power for a period of more than one hour. In contrast to other exchanges, where blocks are usually standardized, APX allows the trading of flexibly definable blocks since October 2001.

APX runs a daily two-side energy auction, where all players can act as buyers or sellers. Bids are made known to APX fully electronically until 10:30 on the day prior to delivery. They express in up to 25 quantity/price pairs how much power (in MWh) a participant wants to buy or sell up to a specific price limit (in Euro, with 2 decimals). Block bids contain two conditions: First, the whole volume has to be accepted by the matching process. Second, the average price over the hours included in the block has to be equal, or better, than the stated price limit (minimum income (sales) or maximum payment (purchases) condition).[15]

3.1.2 *Adjustment market*

The adjustment market at the APX is designed to correct unexpected supply-demand imbalances which arise during the day because of load or generation variations (short-term position improvements by trading relatively small quantities). It is based on a simple model: *hourly prices/volumes* and *block bids*. The adjustment market facilities provide bid and ask prices (in EUR/MWh) and the latest trade volumes, and allow the avoidance of bilateral contracting (which is usually more cumbersome and costly). Based on continuous trade, transactions are determined by price acceptance (i.e. quote-driven, where demand and supply meet) and are executed immediately whenever possible.

3.2 Borzen (Slovenia)

The daily market at the Borzen power exchange started operation on 3 January 2002. There, supply of and demand for electricity for the next working day, or for a period up to and including the next working day, are matched.[16] Additionally, Borzen provides a week-ahead market for so-called 'preferential dispatch' electricity (see 3.2.2.). The number of participants in April 2002 was 16. The average daily traded volume from January 2002 until April 2002 was 2966 MWh (344 MWh for base-load power, 65 MWh for peak-load power, and 26.5 MWh for hourly power, respectively).

3.2.1 *Day-ahead market*

At the Borzen daily market, currently four products are traded (3 block contracts in continuous trading sessions, and 24 hourly contracts in an auction):

- *base-load power* (0:00 – 24:00 hours): the basic quantity/lot is 24 MWh;[17]
- *peak-load power* (6:00 – 22:00 hours; working days only): the basic quantity/lot is 16 MWh;
- *off-peak load power* (0:00 – 06:00 hours and 22:00 – 0:00 hours); the basic quantity/lot is 8 MWh;[18]

[15] When entering a (sales) block bid, the participant defines a block of consecutive hours, a volume applicable for all hours, and a price. The minimum income condition refers to the equation of the number of consecutive hours, the volume, and the limiting price. A block bid can be matched in case the limiting price is equal to, or lower than, the average price throughout the defined block of hours. A block bid must be matched for the entire volume specified, and for all hours. If this is not possible, the block bid is rejected (cf. www.apx.nl/marketresults/aggcurve/disclaimer.html).

[16] www.borzen.si/en_data.htm , additional information results from personal communication with Boris Štraus/ BORZEN

[17] When time changes from winter to summer, 1 lot equals 23 MWh; when time changes from summer to winter, 1 lot equals 25 MWh.

[18] When time changes from winter to summer, 1 lot equals 7 MWh, and when it changes from summer to winter it is equal to 9 MWh.

- *hourly power* (24 hours of one day); the basic quantity/lot is 1 MWh.[19]

There are two types of bids: *market bids* (the participant sets no limit regarding the price) and *limited bids* (the participant sets the acceptable highest purchase and lowest sale price).[20] Volumes are stated in MWh, corresponding to a multiplier of the basic quantity unit (lot) of the product. Prices are stated in SIT[21]/MWh (rounded to the nearest 10 Tolars).

In *auction trading*, the following additional or special conditions for the execution of bids are possible:

- *remaining quantity bids:* this is a special kind of bid made by the market participants after the marginal price has been calculated and the possible remaining unmatched quantity is known; these bids only include the quantity because the remaining quantity is sold at the marginal price.

In *continuous trading*, the following additional or special conditions for the execution of bids are possible:

- *undisclosed quantity bids:* the order book does not reveal the entire quantity of the bid but only part of it; such bids can only be limited bids;
- *"all-or-nothing" bids:* the bids are only executed if the entire quantity of the bid is agreed upon;
- *"stop" limited bids:* the bids are entered in the order book as limited bids only after exceeding, or falling below, a set price;
- *"stop" market bids:* the bids are entered in the order book as market bids only after exceeding, or falling below, a set price.

Trading of hourly contracts is organised as an auction which is divided into several stages: the (a) *pre-trading* stage lasts from 8:00 a.m. until 10:00 a.m., while the subsequent (b) *first-price stage* lasts from 10:00 a.m. until 10:14 a.m. Participants can enter and/or remove their bids during both stages. In the meantime, the market operator publishes data on the best bids. During the first-price stage, the market operator additionally publishes a balanced price for each product separately. When the first-price stage ends, the *market clearing price* is calculated for each product separately. During the (c) *final stage* of the auction, from 10:15 a.m. until 10:30 a.m., the surplus amount is offered; in this stage participants can only purchase any eventual surplus electricity at the calculated marginal price.

Block contracts are settled in continuous trading sessions during from 8:00 a.m. until 10:00 a.m., with a pre-trading stage lasting from 6:00 a.m. until 8:00 a.m. During pre-trading only limited bids without special conditions can be entered and the price and quantity of the sale bid with the lowest price and the purchase bid with the highest price are published. The continuous trading session starts with an opening auction to calculate the price for all transactions concluded on the basis of bids received during pre-trading.

3.2.2 Preferential dispatch trading (week-ahead auction)

In the preferential dispatch trading market, the following products are traded once a week for the following week: (i) *base load* (0:00 – 24:00 hours, Monday – Sunday) and (ii) *peak load* (7:00 – 21:00 hours, Monday – Sunday).

Participants are certain (temporarily) qualified electricity generators nominated by the Slovenian government and generators that use domestic fuel. A qualified generator has, in individual generation

[19] When time changes from winter to summer, trading involves 23 hours of the day, and when it changes from summer to winter it involves 25 hours.
[20] See „Rules of Operation for the Electricity Market" issued by BORZEN Market Power Operator d.o.o. (www.borzen.si/).
[21] SIT = Slovenian Tolar (EUR 1 = SIT 225, USD 1 = SIT 258; approx.).

facilities, to generate electricity with an above-average actually achieved output in the combined generation of electricity and heat, or to use "either waste or renewable energy resources in an economically appropriate way in compliance with environmental regulations". The volume of preferential dispatch electricity is restricted to 15 per cent of the primary energy required to meet the electricity demand of one year according to the Slovenian energy balance sheet.[22]

Trading on the preferential dispatch market is organised as an auction, too. The *pre-trading stage* lasts from 10:30 a.m. until 11:00 a.m. and the *first-price stage* from 11:00 a.m. until 11:30 a.m. Participants may enter and/or remove their bids during both stages. During the first-price stage, the market operator publishes data on the best bids and a balanced price for each product separately. At 11:30 a.m. the calculation of the uniform price starts. When the uniform price is published, the trading for surplus amounts begins and lasts until 12:00 noon. During this stage it is only possible to purchase the eventual surplus amount of electricity at the market clearing price.

3.3 EEX – European Energy Exchange (Germany)

3.3.1 The merger of EEX and LPX

The German power exchanges in Leipzig (LPX) and Frankfurt (EEX), respectively, are currently in a period of transition after the announcement has been made in October 2001 that the two exchanges will be merged after all. The LPX spot market was launched in June 2000 with auction trading for individual hours and block contracts.[23] EEX started operation in August 2000 with a day-head market for individual hour and block contracts settled in auctions and continuous trading, respectively.[24] The number of participants at LPX was around 80 in March 2002. In January 2002, in contrast, 60 participants were admitted to trade at EEX.

The new exchange, named European Electricity Exchange (EEX) and located in Leipzig, will offer its participants trade with already existing products and proven trading systems. More specifically, at the spot market it will offer the *auction market* as well as the *continuous trading*. Trading takes places from Monday to Friday except for pan-German holidays. Therefore traded delivery days are the calendar day following the trading day, all days of the weekend, and pan-German holidays directly after the trading day as well as the trading day directly after weekends and holidays. On Fridays, for example, the products are traded which are actually fulfilled on the following Saturday, Sunday, and Monday.

3.3.2 Auction market

The system of the auction market corresponds more or less to the trading system that hitherto existed at the LPX market.[25] Trading is based on double-sided auctions for every individual hour. Participants can transmit their bids to EEX and can change them via a special Internet software (ElWeb; receipt before 12:00 noon), or by fax (receipt before 11:30 a.m.; backup solution). All bids are collected in a *closed order book* and then used at 12:00 a.m. to calculate the prices.

Individual hour contracts are traded with a minimum of 0.1 MWh (in steps of 0.1 MWh) for day-ahead delivery. Participants at least have to state a volume for the bottom and top price limit defined by EEX and can add 62 price/volume pairs within the price scale. Specifying the same volume for the bottom and top price limit generates independent bids.

Apart from the individual hour contracts, the following blocks are being offered in auction trading:

[22] See also Articles 1 and 155 of the Borzen „Rules of Operation for the Electricity Market" (www.borzen.si).
[23] See www.lpx.de/index_e.asp .
[24] See www.eex.de/content/en_index.html .
[25] Personal communication with T. Pilgram/LPX, 4 June 2002.

- 1 – *EEX Night* (0:00 – 6:00 a.m.)
- 2 – *EEX Morning* (6:00 – 10:00 a.m.)
- 3 – *EEX High-Noon* (10:00 – 2:00 p.m.)
- 4 – *EEX Afternoon* (2:00 p.m. – 6:00 p.m.)
- 5 – *EEX Evening* (6:00 p.m. – 12:00 p.m.)
- 6 – *EEX-Rush Hour* (4:00 p.m. – 8:00 p.m.)
- 7 – *Baseload* (0:00 p.m. – 24:00 p.m.)
- 8 – *Peakload* (8:00 a.m. – 8:00 p.m.)
- 9 – *Off Peak 1* (0:00 a.m. – 8:00 a.m.)
- 10 – *Off Peak 2* (8:00 p.m. – 12:00 p.m.)

Participants state the desired volume and price for a block. The maximum size of an individual block bid has been set to 100 MW, and a maximum of six block bids per participant can be sent.

3.3.3 Continuous trading

EEX provides also continuous trading for three block contracts. The system is taken from the former EEX. The products traded continuously are defined as follows:

- *Base-load contracts* have 24 MWh/lot (equivalent to a constant 1 MW delivery over the period midnight – midnight);[26] the quotation is in unit points of EUR/MWh; the minimum price movement is 0.01 point (corresponding to 1 $¢_{EUR}$/MWh);

- *Peak-load contracts* have 12 MWh/lot (equivalent to a constant delivery of 1 MW in the period from 8:00 a.m. to 8:00 p.m.) and are eligible for Monday to Friday; quotation of unit points is in the same way as for base-load contracts (i.e. unit points of EUR/MWh, minimum price movement 0.01 point, corresponding to 1 $¢_{EUR}$/MWh);

- *Weekend base-load contracts* have 24 MWh/lot (equivalent to a constant 1 MW delivery over the period midnight – midnight) and only are eligible for Saturday and Sunday together; the quotation is in unit points of EUR/MWh; the minimum price movement is 0.01 point (corresponding to 1 $¢_{EUR}$/MWh).

Two basic types of bids are permitted for the price determination process: *market orders* (i.e. unlimited bid and ask orders, to be executed at the best possible price) and *limit orders* (i.e. bid and ask orders which have to be executed at the given limit or better). In addition three special order types are provided:

- *Market-to-limit orders* are unlimited bids of which any unexecuted part enters the order book with the same price limit and time stamp as the executed part;
- *Stop orders* are entered into the order book automatically as a market or limit order, as soon as the given stop limit is reached (undercut or exceeded);
- *Iceberg orders* are a number of consecutive orders with the same limit and quantity; only the first order is visible in the order book; when the first order is executed, the second order becomes visible, etc.

Several execution conditions and trading limitations are selectable to specify the bids:

- an *immediate-or-cancel (IOC) order* is an order which is immediately executed either in its entirety or as much as possible. Those parts of an IOC order which are not executed are deleted without being entered into the order book;

[26] When the clock is changed from wintertime to summertime, the lot comprises 23 MWh, and when it is changed again from summertime to wintertime, the lot comprises 25 MWh.

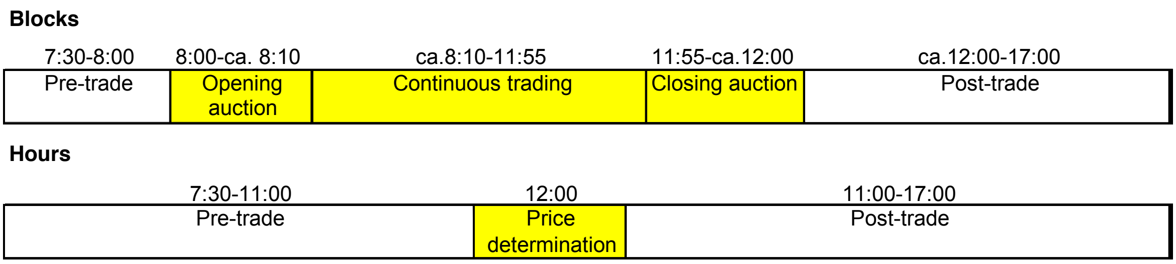
- a *fill-or-kill (FOK) order* is an order which is either executed immediately in its entirety or not at all; if complete execution is not possible immediately, the FOK order is deleted without being entered into the order book
- bids can be restricted to auctions only, to the opening auction only, or to the closing auction only;
- an accept surplus order is an order which is permitted during order book balancing phases only.

Continuous trading starts at 7:30 a.m. with the *pre-trading phase* in which the participants can submit bids and the order book is closed (see also Figure 4). In order to be able to process all orders from the pre-trading phase and to be able to determine an objective reference price at the start of the trading, the trading of blocks begins at 8:00 a.m. with an *opening auction* that includes a *10-minute call phase*, during which participants can enter new orders and change or delete their own existing orders. In order to counteract price manipulation, the call phase has a *random end* within a time period of 30 seconds after which the auction price is calculated. The price is valid for all transactions to be made up to this moment. The auction ends with an *order book balancing phase* when there is any surplus. For a limited time period the surplus is offered at the auction price and can be accepted by entering accept surplus orders.

At the end of the opening auction, all unexecuted or partially executed orders are taken up into *continuous trading* (insofar as traders wish). Continuous trading is followed by a *closing auction* at 11:55 a.m. After a call phase of 5 minutes with a random end within 30 seconds, price determination takes place in a similar manner as in the opening auction. Again price determination may be followed by an order book balancing phase in case if there is any surplus.

The trading day ends with a post-trading phase for the processing of all executed trades.

Figure 4. Phases in continuous trading at EEX



Source: own illustration

3.3.4 Transmission constraints and bid areas

The market is divided into *bid areas* that are defined by EEX.[27] Market participants can only place bids for a bid area if he/she is part of a balance area in the relevant bid area, and all bids received by EEX will be assigned to a particular bid area. In case of transmission constraints individual supply and demand curves are aggregated per bid area resulting in a market clearing price for every bid area. Different prices in the bid areas are adjusted by using price-independent demands and supplies to create power flows from bid areas with low market clearing prices to bid areas with high market clearing prices. If the transmission capacity between the bid areas involved constrains a complete levelling, the bid areas form price areas. Otherwise the market clearing price is the same for all areas and is valid for all trades carried out.

[27] A bid area either consists of one TSO area or several connected TSO areas where the transmission system operators involved have agreed to cooperate concerning activities at the interface to EEX. Normally, the bid areas correspond with the TSO areas, as defined in the Verbändevereinbarung II plus (of 13 Dec 2001; see www.bmwi.de/Homepage/ download/energie/VVStrom.pdf).

3.4 EXAA – Energy Exchange Austria (Austria)

Trading on the day-ahead market of the Energy Exchange Austria (located in Graz, Styria) was launched in March 2002.[28] Currently, only hour contracts are available, but it is planned to provide futures contracts in 2003, and block contracts if the need should arise. It is also envisioned for the future to implement an adjustment market. In the first month of operation of the EXAA, average daily traded volume has been about 2,000 MWh, traded by 13 members of the exchange.

From Monday to Friday, a double-sided auction is carried out.[29] The participants can submit purchase and sale bids anonymously and only via the Internet between 8.00 a.m. and 10.00 a.m. for all 24 hours[30] of the next day. There are three possible types of bids: First, *market orders*, which are price independent, i.e. they are executed at the market clearing price. Second, *step orders*, for which volumes and prices are quoted stepwise. Third, *linear orders*, for which volumes and prices are quoted as a linear interpolation. The minimum size of the order is 1 MWh and the minimum tick size is EUR 0.01. These orders are collected in the sealed order book. The prices for every hour are calculated until 10.15 a.m. and then publicly announced.

Transmission constraints are managed by market splitting. The market area is split into trade zones,[31] and the participants have to assign every bid to one of these trade zones. If there are transmission constraints between trade zones, then a market clearing price can be calculated for every trade zone concerned. To minimize the differences between market clearing prices of the trade zones and of the whole market area, the available transmission capacities are fully exploited to alter aggregated demand or supply in a trade zone and the trade zone price, respectively. If the transmission capacities are not sufficient to equal the prices, different prices are used for executed transactions in the different trade zones.

3.5 GME – Gestore Mercato Elettrico (Italy)

The launch of the Italian power exchange market is scheduled for October 2002. The exchange will eventually provide five markets:
- day-ahead market
- adjustment market
- congestion management market
- reserve market
- balancing market.[32]

In the next two subsections, as the market is not yet in operation, we will restrict our discussion to the planned day-ahead energy market and the adjustment market.

3.5.1 Day-Ahead Energy Market

In the day-ahead market hourly contracts will be traded in daily double-sided auctions one day in advance of delivery. Market participants are allowed to submit multiple sale bids for a single generating unit, or point of interconnection with a foreign country, provided that the prices of the bids do not decrease with increasing quantities. Multiple purchase bids can be submitted for a single point

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[28] See www.exaa.at , additional information results from personal communication with C. Kawann/EXAA.

[29] On Fridays, hour contracts for Saturday, Sunday and Monday are traded.

[30] Note that on the day the time changes from winter to summer time, the 3rd hour is not tradable, and on the day the time changes from summer to winter time, the 3rd hour automatically is taken into account twice.

[31] At the moment Austria is divided into three trade zones – the three grids of Austrian Power Grid GmbH, Tiroler Regelzonen AG, and Vorarlberger Kraftwerke-Übertragungsnetz AG –, corresponding to the term "Regelzone" defined in the Austrian Electricity Act (ElWOG 2000).

[32] See www.mercatoelettrico.org .

of withdrawal or of interconnection with a foreign country, provided that these bids are not increasing in price with increasing quantities. Bids from both sides can also be price independent.

If there are transmission constraints, GME will divide the market into two or more zones to be able to select the bids in each zone in accordance to the available grid capacities.

3.5.2 Adjustment market

GME also plans to provide an adjustment market with two sessions. The first will take place after the closure of the day-ahead market, covering all hours of the next day; the second will take place in the morning of the next day, covering all the hours of that day remaining after the closure of the session. Trading will be very similar to the day-ahead market. Hourly contracts are going to be settled in auctions with bids from the supply and the demand side. Quantities can be offered and demanded with or without price limit. In case of transmission constraints, again market splitting will be applied.

3.6 Nord Pool (Norway / Sweden / Finland)

Nord Pool launched its day-ahead market in 1993 and its adjustment market in March 1999.[33] 216 participants were allowed to trade on the spot market in December 2001.

3.6.1 Elspot (day-ahead market)

The Elspot day-ahead power market is a market with physical delivery. The products traded are power *contracts with one hour duration* and *block bids*. The *hourly contracts* cover all 24 hours of the following day. Currently, there are five block periods approved for trading in the day-ahead market:

- Block 1 – 1:00-7:00;
- Block 2 – 8:00-18:00;
- Block 3 – 19:00-24:00;
- Block 4 – 1:00-24:00;
- Block 5 – 8:00-24:00.

Prices at Elspot are determined through auction trade for each delivery hour. Each sale/purchase bid is a sequence of price/volume pairs for each specified hour with a minimum size of 0.1 MWh/h.

Bids are submitted to the marketplace either electronically via Internet, or by fax on special bid forms, before noon (deadline). Purchases are designated as positive numbers, sales as negative numbers.

3.6.2 Elbas (adjustment market)

The adjustment market "Elbas" aims to improve the balance of physical contracts of the participants.[34] The trading products are one-hour physical delivery contracts, which can be traded up to 1 hour before delivery. This market is currently limited to Sweden and Finland, but the inclusion of further Nordic countries is under consideration.

Elbas offers *continuous trading* all around the clock and every day. The trading session for a specific day starts after the publication of the results of Elspot for this day. Bids can be submitted electronically or by phone (helpdesk). Their minimum size is 1 MWh and prices are quoted in Euro with a minimum tick size of 0.1 Euro.

Grid congestion is relieved in two different ways: (a) within Norway and at the interconnections between the Nordic countries by introducing *different market area prices*; and (b) within Sweden, Finland and Denmark by *counter-trade purchases* based on bids from generators. The *system price* in

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[33] See www.nordpool.no . Nord Pool also runs a balancing market, that is analysed by Skytte (1999).
[34] See www.elbas.net .

the Elspot market is the market clearing price for Elspot power in the absence of grid congestion, calculated once the bids from all participants have been received. The total market is divided into bidding areas, which may become separate price areas if the contractual flow of power between bid areas exceeds the capacity allocated for Elspot contracts by transmission system operators (TSO). In the case of *grid congestion*, two or more area prices are created.

3.7 OMEL - Spanish Power Exchange (Spain)

OMEL provides power trading on a day-ahead and on an hour-ahead market since January 1998.[35] In September 2001 the number of participants was 79.

3.7.1 Daily Day-Ahead Market

Most transactions at the OMEL are carried out on the double-sided day-ahead daily market, where hour contracts for every hour of the day following the auction are traded. The sale bids may be simple, or may include (optional) additional conditions. Simple offers are presented as at most 25 price/volume pairs for each hourly period and production unit. Complex bids, in contrast, also include some or all of the technical or economic conditions shown in Table 2.

Table 2. Technical and economic conditions for complex bids at OMEL

Sale bids	Purchase bids
Simple bids:	*Unpriced bids:*
• upward supply curve	• rigid demand curves
Complex bids:	*Priced bids:*
• indivisibility	• downward demand curve
• minimum income	
• load gradient	
• scheduled shutdown	

Source: OMEL

A bid includes the volume stated in MWh and the price stated in Euro/kWh. If a bid shall be submitted not only for one day, it can be set to a default bid which means that the order is automatically put to every day's order book. At OMEL purchase and sale bids are matched that are received before 10:00 a.m.

3.7.2 Intra-Day (Hour-Ahead) Market

Once a technically viable daily schedule has been published, the market operator starts to run several sessions of the hour-ahead market, in which participation is voluntary. The bid structure and the matching processes in the hour-ahead market are similar to those in the day-ahead market – except that the solution will be added to the previous market results and that some complex conditions (e.g. gradients) are applied over the complete schedule (i.e. previous market *and* current hour-ahead result).

The intra-day market currently comprises six daily sessions over time horizons between 9 and 28 hours. Multiple sale and/or purchase bids may be presented for each production/by each purchasing unit. Each bid consists of up to five price/volume pairs for each hour, and may additionally include optional conditions as well (load gradient, minimum income or maximum payment, complete acceptance in the matching process of the first block of the bid, complete acceptance in each hour in

[35] See also www.omel.es . For a more detailed description of the Spanish power exchange see also Gonzalez and Basagoiti (1999).

the matching of the first block of the bid, minimum number of consecutive hours of complete acceptance of the first block of the bid, maximum matched power).

Just like in the day-ahead market, network constraints are not taken into account for the matching process. After the unconstrained hour-ahead market results are obtained, they are sent to the system operator who checks the viability of the transactions. Non-viable transactions are eliminated, taking account of the economic merit orders of the hour-ahead bids, and the schedule is balanced again.

3.8 Powernext (France)

Powernext, launched in November 2001, is an "optional and anonymous organized exchange for the delivery of electricity into the French hub".[36] It offers *standard hourly contracts* negotiable on a daily basis by French generators and foreign players acting on their own behalf. Current number of participants is 18 (April 2002). Transaction liquidity is established by concentrating bids on an auction. In the first six months (November 2001 to April 2002) the turnover accumulated to 515 GWh. There are plans to launch block products, standardised futures contracts, to extend to other hubs, and to introduce bilateral contract clearing via the central counterparty 'Clearnet', used to improve financial security and physical deliveries of power.

Hourly product trading and quotations are undertaken on an Internet-accessible platform. The negotiation system used acts as a centralised order book that calculates and distributes the market clearing price and market clearing volume. Market participants may place their bids from Wednesday of the previous week at 5:00 p.m. until 11:00 a.m. on the auction day. The content of the order book is not disseminated during the pre-auction period. On the auction day at 11:00 a.m., market clearing prices and volumes are determined. The participants then have 15 minutes to raise any potential disputes.

The system, for technical reasons, displays the default price limits in the order form. The bottom limit is currently set at zero Euros and the top limit at EUR 3,000. Within these two limits, members can parameterise up to 62 prices between the top and bottom limits, which leads to a total of 64 price/quantity pairs that can be offered by hour and for the 24 hours of the following day. The minimum price tick is EUR 0.01 per MWh. Quantity must be in whole MWh. Positive (negative) quantities correspond to purchases (sales).

Table 3 provides a summary for the hourly products traded at Powernext, while Figure illustrates the Powernext trading schedule.

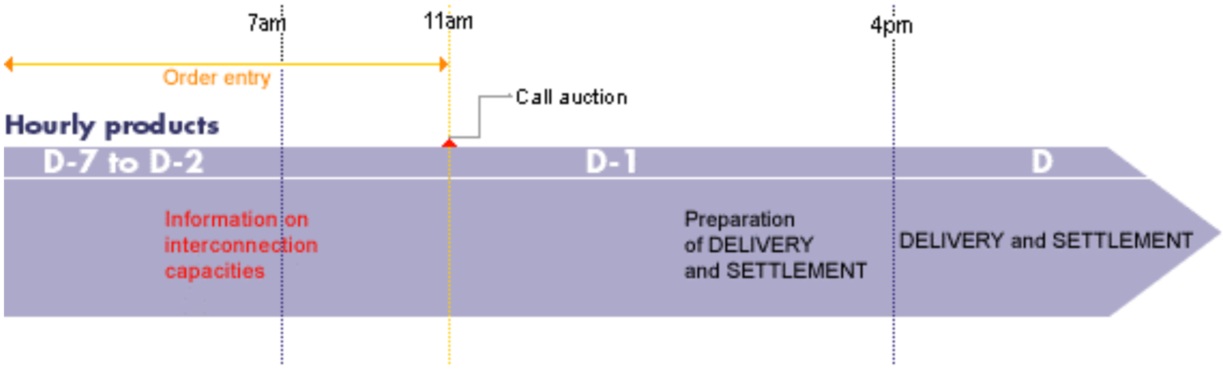
Table 3. Summary of the Powernext hourly products

Characteristic	Description
Product definition	24 separate hour periods throughout the following delivery day (Mon – Sun)
Trading system	ElWeb (Internet interface)
When to place orders	between Wed of the previous week at 5:00 p.m. and 11:00 a.m. on the trading day
Fixing times	11:00 a.m., seven days a week (dispute settlement period: 15 min.)
Minimum volume step	1 MWh
Minimum quotation step	EUR 0.01 / MWh
Quotation method	blind auction by linear interpolation
Order wording	up to 64 price/quantity combinations for the 24 hourly intervals of the following day
Delivery point	French electricity grid (French hub), managed by RTE
Settlement	Market clearing price x volume traded

Source: Powernext

[36] See www.powernext.fr . Note that Powernext transactions can be delivered *at any point* into the French grid.

Figure 5.Trading Schedule at Powernext



Source: Powernext

3.9 UKPX / APX UK / UK IPE (United Kingdom)

In the United Kingdom, despite the early liberalisation of the electricity market in 1990, power exchanges have developed only recently. Until March 2001 a pool-based market existed through which all physical supplies of bulk electricity was traded.[37] This day-ahead market has been running by the National Grid Company (NGC), i.e. the system operator. All generators who wished to have their plant(s) dispatched, had to submit their bids to NGC. NGC constructed a supply curve by stacking the bids in price merit order, and identified the optimal (lowest cost) combination of generation plants that would meet its forecast of demand in each of the 48 half-hourly periods of the next day. It also calculated the uniform price according to the bid price of the most expensive generating set that would have to run in each half–hour. Consumers had also to pay a uniform price, but had no direct involvement in the price setting mechanism except for a few very large power users.

Because of the belief that the pool system allowed to keep market prices well above marginal production costs, the New Electricity Trading Agreement (NETA) was introduced, replacing the pool with a system of voluntary bilateral markets and power exchanges. The new trading system pays generators not in a uniformly but in a discriminatory fashion with their own bid prices. Since the introduction of NETA, three main cleared power exchanges have developed – the UKPX, the APX UK, and the UK IPE. The former two are trading significant volumes of power in the short-term markets, while the latter currently provides futures contracts only, so that it is not going to be discussed any further here.

3.9.1 UKPX

The UK Power Exchange (UKPX) was launched in June 2000. At the beginning of its operation it only provided futures contracts (6-month, 3-month, 4 to 5 weeks, week and day contracts[38]). In March 2001 a round-the-clock spot market went live, where half-hour contracts are traded in lots of 0.5 MWh. They are traded from 10:15 p.m. two days before the flow period in question until 4 hours before delivery. Two new products were introduced in April 2002: block hour and day-ahead contracts, which are tradable all around the clock until 4 hours before delivery. Block hour contracts cover 4 subsequent hours and are listed for trading at 10:15 p.m. three days prior to the flow period in question. Day-ahead contracts are available as base load (constant flow of 1 MW of electricity per hour for the period 11:00 p.m. to 11:00 p.m. next day, daily) and as peak load (constant flow of 1 MW

[37] See Bower, John and Derek Bunn (2001): 568-570.
[38] All these contracts are available as base load (constant flow of 1 MW of electricity per hour for the period 23.00 to 23.00 daily) and as peak load (constant flow of 1 MW of electricity per hour for the period 07.00 to 19.00 for each of the days Monday to Friday). See www.ukpx.com for more details.

of electricity per hour for the period 7:00 a.m. to 7:00 p.m. for each of the days, Monday to Friday). They are listed for trading at 10:15 p.m. two days prior to the flow period in question.

Trades on the UKPX currently account for most of the non-OTC-traded contracts. In April 2002 a total of 44 participants traded at the UKPX.

The price quotation for all contracts is in Pounds Sterling per MWh, with a minimum tick size of £0.01. Spot contracts are traded continuously. Participants submit bid and offer prices, which are posted. Trades are matched continuously where these prices match or are bettered. Pricing follows the pay-your-bid rule, i.e. there is no uniform price for a specific product. Moreover, there are no restrictions to the aggregated trade volume, as transmission constraints are not relevant to this market.

3.9.2 APX UK

The APX UK spot market started in March 2001 and counted 30 participants in November 2001. It provides continuous trading of contracts for physical electricity – so-called *electricity forward agreements* (EFA) - in lots of 1 MW via an anonymous electronic trading platform.[39] APX UK intends to introduce exchange-traded forward products as soon as a market need should arise.

Traded products are 48 half-hour contracts available on a rolling basis, 2-hour and 4-hour blocks, day peak (from 7:00 a.m. to 7:00 p.m.) and day base contracts, balance of week (Monday to Friday, Tuesday to Friday, Wednesday to Friday, and Thursday to Friday) and weekend contracts. The market opens up to 12 days prior to the trading day and closes four hours prior to delivery time. Trading takes the same form as at the UKPX (i.e. continuous trading).

3.9.3 Balancing market

In order to enable NGC (the system operator) to balance the system after gate closure, i.e. after all trades have been centrally notified, a balancing market has been established. Furthermore, *"[p]articipants submit to NGC pairs of offers (to sell power) and bids (to buy power) prior to gate closure. Offers represent the ascending price the participant will require from NGC to provide incremental increases in output (or reduction in demand). Bids represent the diminishing payments a participant is willing to make to NGC in order to reduce the level of generation or increase demand. NGC can call any offer or bid submitted for a particular half-hour, at any point up to real-time, provided that the instruction is in keeping with the plant's dynamic parameters. A generator's accepted bids and offers will be treated as separate contracts and will not cause a balanced generator to go into imbalance (or improve an imbalanced generator's position)."* [40]

4 Summary and Conclusions

In this paper we have addressed both some general theoretical considerations and the actually implemented, or almost implemented, exchange-based spot markets for electricity in Western Europe. The information contained in the paper should provide useful as a starting point for the design of bidding tools that can be used by power-only, and combined-heat-and-power (CHP), generating companies for generating bids to be used in a liberalised market environment. Whereas the literature survey and the overview of important issues with regard to such markets has shown that there are many (and often rather complex) issues that need to be tackled, the empirical part provides an overview of the main features, and the most recent development, of the most important of these markets in Europe to date.

[39] See www.apx.com , additional information results from personal communication with C. Crane/APX
[40] Ibid.

Apart from plant-specific factors, the generation of optimal bids, and bidding strategies, is crucially dependent on the particular market structure, the auction mechanism concerned, and the particular information that can be received. And although it would be useful to obtain and take into account information on the bidding strategies used by competitors (derived, for example, from a model that exploits data on historical market actions), this is information that is generally not easily available, and the modelling issues involved are far from trivial. Besides, the development and evaluation of complete bidding strategies requires both the modelling and the simulation of the market, and a dynamic restructuring of the bidding strategy chosen in reaction to market changes and changes in competitive bidders' behaviour. This, however, is well beyond the scope of the OSCOGEN project for which this report has been produced.

Acknowledgments

We are grateful for comments received from various OSCOGEN team members, in particular from Alfred Hofmann of BEWAG, Berlin, and for funding received from the Swiss Federal Agency for Education and Science (BBW), Berne. The usual caveat applies.

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Links to Power Exchanges Discussed

AUSTRIA:	Energy Exchange Alpen Adria (EXAA) www.exaa.at
FRANCE:	Powernext www.powernext.fr
GERMANY:	European Exchange (EEX) www.eex.de/content/en_index.html
	Leipzig Power Exchange (LPX) www.lpx.de/index_e.asp
ITALY:	Gestore Mercato Elettrico (GME) www.mercatoelettrico.org
NETHERLANDS:	Amsterdam Power Exchange (APX) www.apx.nl/main.html
NORWAY:	Nord Pool www.nordpool.no
SLOVENIA:	Borzen Power Exchange (Borzen) www.borzen.si/en/about.htm
SPAIN:	Spanish Power Exchange (OMEL) www.omel.es,
	www.comel.es/en/reglas_contrato/mreglasconadhesionfr.htm
UNITED KINGDOM:	The UK Power Exchange (UKPX) www.ukpx.com
	Automated Power Exchange UK (APX UK) www.apx.com
	UK International Power Exchange (UK IPE) www.ipemarkets.com

Glossary (Selection of Terms)

- **Balanced offer**

  The term “balanced offer” refers to an offer that is submitted on the adjustment market, which consists of zero-priced supply offers and non-price-dependent demand bids such that the respective quantities are balanced; balanced offers may be submitted by different market participants, provided they refer to the same geographical area.

- **Bidding area**

  Part of the market which usually corresponds to the area of a TSO and may form a separate price area in case of constraints in the transmission from and/or to other bidding areas.

- **Block bid**

  Offer to sell or buy the same quantity of energy for a period of consecutive hours.

- **Discriminatory pricing**

  Discriminatory pricing means that each bidder (generating company) gets paid corresponding to its bid; this is in contrast to uniform pricing where every bidder gets the same price.

- **Heuristic selection**

  In some cases, the dispatcher has to use heuristic selection in order to find a market outcome, so that no ‘fair’ solution may exist.

- **LaGrangian relaxation (LR)**

  LR is an optimisation technique that decomposes the main and usually complex mathematical programming problem into simpler sub-problems that are additively separable by relaxing the hard (e.g. coupling) constraints; each (separately solved) sub-problem is coupled through common LaGrangian multipliers, one for each period; the LaGrangian multipliers at each iteration are updated until a near-optimal solution is found (cf. Dekrajangpetch and Sheblé 1999).

- **Limited bid**

  Offer to sell or buy energy up to a price limit.

- **Lot**

  Basic quantity unit.

- **Market bid**

  Offer to sell or buy energy at the price determined by the exchange.

- **Minimum income condition**

  The minimum income condition assures that a block bid will not be accepted by the matching algorithm if the minimum income requested by the participant is not fulfilled.

- **Multiple-bid auction**

  In a multiple bid auction the market participants submit multiple bids for a single applicable period of time and for a single generating unit by splitting the total quantity of energy offered to the market into multiple bids.

- **Multiple-period auction**

  In a multiple-period auction the participants submit bids for several periods of time separately.

- **Multiple-unit auction**

  In a multiple-unit auction the firms split the total quantity of energy offered into separate bids for each generating unit.

- **Ordinary bid**

  Offer to sell or buy a specified quantity of energy for a single hour.

- **Strategic bidding**

  Strategic bidding refers to the bidding behaviour of individual suppliers that is not solely based on cost considerations, but merely aimed to raise the price above the competitive level (in order to increase profits, or to yield contracts which can otherwise not be obtained).

- **Tacit collusion**

  Tacit collusion occurs when independent market participants exhibit some form of 'cooperative' bidding behaviour, without communication before the actual auction takes place, in order to obtain a better result as compared to a non-cooperative bidding situation.

- **Unconstrained market clearing price**

  Price resulting from the auction trade system of the spot market without considering capacity constraints.

- **Undercutting**

  Undercutting is the submission of a bid for a generating unit that would otherwise be excluded from the dispatch schedule, with a lower price than the equilibrium bid of a competitor, to increase one's output.

New Bid Structures for Power Exchange with Modelling in ILP Framework

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***Abstract*— Block bid were introduced in power exchanges to allow generators with high fixed cost component (start-up and shut-down cost) participate in the market. However, block bid has been designed with very simple structure. Rigid structure in block bid often leads to them being rejected paradoxically. With this factor as motivation, we present new bid structures which retains objective of block bid, but brings in more flexibility, resulting in more liquidity in market.**

***Index Terms*— Power Exchange, Block Bids, Paradoxically Rejected Bids, Integer Linear Programming**

Glossary

$\mathcal{B}$	Set of binaries, i.e. 0 and 1, 3
$\mathcal{R}$	Set of real numbers, 3
$\mathcal{R}^+$	Set of positive real numbers including 0, 3
Block Bid	Such bid specify fixed volume that, if cleared, has to be delivered over a certain number of consecutive time slots. It is cleared if average MCP over operation time horizon is more than (or less than for loads) specified price limit., 1
Fill-And-Kill	Under this specification, bid can be accepted partially but it should be scheduled in fixed time slot. Remaining volume is immediately canceled. Abbreviated as *FAK*, 3
Fill-Or-Kill	Bid with this nature have to be either executed in complete volume at a fixed execution time or canceled altogether. Abbreviated as *FOK*, 3
PRB	Paradoxically Rejected Bids. Bid which confirms to the market clearing price but still is forced out of market or rejected., 1

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I. Introduction

Power Exchange (PX), is a platform to trade power in a day ahead market for each time slot, each slot being typically of one hour, thought 15 minutes and half hourly slots are also in practice. It provides a spot market (mainly day-ahead), which like any other market matches demand and supply for each time slot (typically of an hour), while providing a public price index

One of the simple most market model will consists of buy bids and sell offers for each hour, where each participant submits his demand/supply curve. Any of these orders may then be met completely, partially or rejected altogether. A common market clearing price (MCP) is declared and based upon these price, bid scheduling takes place.

- If a bid is above MCP, it is selected completely.
- If a bid is below MCP, it is rejected altogether.
- If an offer is below MCP, it is selected completely.
- If an offer is above MCP, it is rejected altogether.
- If any of the bid/offer is exactly at MCP, it may be selected, rejected or partially scheduled.

Since, supply and demand should be equal (neglecting losses) to maintain power balance in real time, this MCP will come at intersection of aggregated demand and supply curves.The above mentioned equilibrium also maximizes social welfare.

Various exchanges provides different bidding options to accommodate a wide range of customers. As for example, due to technical constraint (say generator having high start up and shut down cost) participating in decoupled hourly market may be risky, or may have to bid very high, thereby lowering the probability of his bid being selected. To account for such participants and bring more flexibility in the market, PXs have come up with product commonly referred as *block bid* [1], [2]. This kind of bid has three important characteristics:

1) Multi-hour operation,
2) Constant volume operation, and,
3) Selection criteria based upon average MCP.

This means that a block bidder bids for multiple contiguous hours at once, and in case his bid is selected agrees to supply/consume constant power over these consecutive time periods. Also, his bid can be selected based upon average price expected by participant. Thus, player might be making loss in one hour, but may be compensated in next hour and hence, overall be in money. Block bidding also allows participation of those generators, which are technically constrained to produce power for certain number of hours once scheduled. Some exchanges restrict block bidding to pre-defined block periods, called as strips, whereas in other exchanges trader are be allowed to choose his own block.

Incorporation of block bids leads to market clearing problem across various hours being coupled. Thus, simple approach of intersecting supply and demand curve cannot be applied. In fact, exchanges mostly apply heuristics to clear the market [3]. These heuristic approach, however, does not guarantee optimal scheduling. Block bids leads to another complexity, that price signal may not be sufficient to dictate acceptance and rejection of bids while maintaining supply and demand balance. Exchanges handle this problem by forcing certain block bids to be rejected, even when at clearing prices trader qualifies for selection. Such rejected bids are termed as *Paradoxically Rejected Bids (PRBs)* [4].

Both the above mentioned problems, market clearing getting tougher and bids being rejected paradoxically, are due to the inflexibility in block bid structure. While first problem can be handled by developing more sophisticated algorithms, second issue requires evolution of bid structures to account for technical constraint as well as allowing certain degrees of flexibility.

Even if PRB issue is not that critical, with market maturing over the time, exchange have to explore more flexible options [4]. Requirements will be felt to model trader's technical constraints more accurately. In this paper, we take a step forward in this direction and propose few additional bid structures meeting the above mentioned goal. In particular, we address problem of modelling start up, shut down costs and ramping costs along with marginal cost in bid structure itself.

Mixed Integer Linear Programming (MILP) has been widely used in power system problems in last decade[5],[6],[7]. Though solving MILP is theoretically a tough problem, various techniques have been developed which can handle most of the practical problems with ease. Such a framework has been developed in [4] to handle block bids. In this paper, we extend this model to incorporate proposed bid structures.

II. Paradoxically Rejected Bids

To understand PRBs, let us consider a simple example of single hour market clearing problem. Suppose following bids/offers are received:

1) Normal bid to buy power up to 100 units of power at price of 7 monetary units (MUs),
2) Normal offer to sell power up to 50 units of power at price of 3.5 MUs,
3) Normal offer to sell power up to 25 units of power at price of 4.0 MUs, and,
4) Block offer to sell 50 units of power at 4.5 MUs,

Now it can be easily shown that there exists no price which by itself enforces appropriate bid acceptance and rejection. If market clearing price p is declared such that $3.5 < p < 7$, then hourly bids and offers have to be scheduled completely. In such a case, there is imbalance of 25 MUs. Now this imbalance cannot be met by rigid block bid of size 50 units each. If $p = 7$, then buy bid can be scheduled partially or completely, but going by price signal all other sell bids qualify. Similar observation can be made when $p = 3.5$. Thus, price is not enough to determine selected set of bids/offers. Some bids have to be forced to rejection even when they are meeting price criteria.

Allowing social welfare maximization determine appropriate schedule will lead to complete selection of buy bid, hourly offer to deliver 50 units and block bid of 50 units. clearing price can be anywhere 4.5 to 7. Consequently, hourly offer willing to deliver power at lower price of 4 MU is rejected. Net social welfare comes out to be 300.

However, exchanges across the world practice the policy that if price criteria is met by hourly bids, then they should be scheduled, even if it means *meeting* goal of overall social welfare to a *lesser extent* possibly coupled with lower traded volume. Also, bids/offers exactly at market price can be scheduled partially. Hence, honoring above mentioned constraint, solution to our problem will be to schedule hourly bids of 100 units along with both hourly offers, leading to overall traded volume of 75 units and social welfare of 250. Clearing price has to be 7 MU, as buy bid is getting partially scheduled.

Observations, based upon above example, can be summarized as follows:

1) Block bids, due to their rigidity, makes market clearing problem complex, both from computation as well as policy perspective,
2) If only social welfare maximization is the criteria, then more competitive normal bids/offers may have to be rejected (paradoxically) due to rigidity of block bids, and,
3) If policy to accept bids/offers meeting the market clearing price is followed, then social-welfare along with net traded volume may be compromised. Also, certain block bids might be paradoxically rejected.

Looking into above facts, one of our motivation while devising new bid structures would be to mitigate paradoxical effects of block bids, while meeting the objective of introduction such an instrument.

III. Need of Block Bids

Block bid was introduced to encourage generators with high start-up and shut-down cost, typically thermal ones. As for example consider a generator which incurs cost of 5 MU per unit of power delivered. However, in has also to recover start-up and shut-down cost of 200 MU. It can deliver up to 50 units. Now, if this trader has to bid for single hour, no matter how much volume he delivers, minimum cost of 200 has to be recovered anyhow. If he has option of delivering either full 50 units of volume or none, then he has to bid $200+5\times 50 = 450$ for 50 unit of power or 9 MU.

Now let us take a case where trader is allowed to bid for consecutive 4 blocks of hours. Now he has to bid so as to recover $200 + 4 \times 5 \times 50 = 1200$ for 5 hours of supply of 50 units of power. Thus, in this case he is bidding 6 MU, which is more competitive than former. This is because, fixed cost corresponding to start-up and shut-down is distributed over multiple hours. This is precisely the reason that exchanges have incorporated block bids.

In subsequent sections, we develop advanced structures and develop corresponding MILP model. The developed model can be then, easily integrated with the MILP framework developed in [4].

IV. Development of Advanced Bid Structures

We revisit example from section II. If in this case, block bidder had the idea that size of his bid will be too large to be selected and only 25 units will be the market requirement, he would have bid accordingly. He would have quoted for 25 units of power only but at higher price say 6 MU, as fixed cost have to be recovered over small amount of volume. This way, even this bid could have entered the market and make profit.

Nevertheless, deriving such a priori information may be impossible. Hence, a bid structure is required where he can segregate associated fixed cost and volume dependent cost while putting up his quotation and also allowing him to bid for a range of volume and not a fixed quantity.

In essence, rather then specifying fixed volume and minimum average MCP, bidder can specify, volume range and other parameters to derive minimum income to be recovered. This bid structure can be thought of as hybrid of FOK and FAK, where if selected minimum volume has to be at least filled completely and rest can be partially filled and hence, can be given the name *Fill Minimum or Kill (FMOK)*.

Based upon mode of schedule profile, two possible operations can be thought of:

Constant Volume: Under this mode of operation, generator will get volume schedule, within specified limits, which will remain constant throughout the bidding execution period.

Variable Volume: Under this mode of operation, generator can get variable schedule for each time slot but will remain with in allowed range.

Variable scheduling scheme adds another dimension of flexibility. Benefit of this scheme is that bid will not be rejected because in one hour requirement is more, whereas in next low volume has to be met. If volume has to be kept constant then it is possible that normal hourly bids, even being priced higher, may get priority.

While putting up such a bid, trader has to specify following information

1) Start-up cost $\alpha^{\uparrow}$,
2) Shut-down cost $\alpha^{\downarrow}$,
3) Fixed running cost ω, and,
4) Some model to specify marginal cost (volume dependent variable component).

Based upon what model is used to specify marginal cost, we come up with variants which are being discussed now.

Remark 1. *Even though modelling is being carried out from supplier's perspective, similar model can be built for consumer as well.*

A. Constraint Modelling of Proposed Bid Structures

We now develop MILP model, which can be integrated with model proposed in [4], to represent selection criteria on proposed bid structures.

1) Constant Marginal Cost: Under this structure, marginal cost is specified with the help of single parameter β, which is marginal cost for delivering single unit of power. Thus, if V amount of power is delivered, net marginal cost will come out to be βV.

Constant Volume Schedule: For a block bid over a period of h_1 to h_2 under this scheme, let us introduce $V \in \mathcal{R}^+$ as scheduled volume variable and $s \in \mathcal{B}$ to represent bid selection.[1] Then, following constraints models financial of the generator

- Volume scheduling constraint
  - If bid is not selected then scheduled volume $V = 0$, and,
  - If bid is selected then $V_{min} \leq V \leq V_{max}$

  This constraint can be modelled as

$$sV_{min} \leq V \leq sV_{max} \tag{1}$$

- Minimum cost recovering constraint
  - If bid is not selected then there is no cost to be recovered, and,
  - If bid is selected with scheduled volume being V, then minimum cost to be recovered is

$$\alpha^{\uparrow} + \alpha^{\downarrow} + (h_2 - h_1 + 1)\,\omega + (h_2 - h_1 + 1)\beta V$$

  Thus, minimum income criteria can be modelled as,

$$V \sum_{h=h_1}^{h_2} \mathrm{MCP}_h \geq s(\alpha^{\uparrow} + \alpha^{\downarrow}) + s(h_2 - h_1 + 1)\,\omega + (h_2 - h_1 + 1)\beta V \tag{2}$$

Ineqn 1 models range of power volume that can be scheduled. If bid is not selected ($s = 0$), upper and lower bound both becomes 0, forcing scheduled volume to be 0. On the other hand, if bid is selected ($s = 1$), lower bound becomes V_{min} and upper bound becomes V_{max}.

Ineqn 2 models minimum income criteria. If bid is not selected, both sides of this relation become zero, thereby honoring the above mentioned relation. However, if bid is selected, then net income coming out of declared MCPs should be more than or equal to sum of fixed cost and variable cost. Note that this relation results in non-linearity, quadratic to be more precise. However, this *problematic* quadratic term can be approximated by linear set of relations as discussed in appendix I.

Variable Volume Schedule: For a block bid over a period of h_1 to h_2 under this scheme, let us introduce $V_h \in \mathcal{R}^+$ as scheduled volume variable for each time slot $h \in \{h_1, h_1 + 1, \cdots, h_2\}$ and $s \in \mathcal{B}$, to represent bid selection. With slight modification over previous model, we arrive at following model, which allows volume fluctuation across contiguous time slots in single block

$$sV_{min} \leq V_h \leq sV_{max} \quad \forall h \in \{h_1, h_1 + 1, \cdots, h_2\} \tag{3}$$

$$\sum_{h=h_1}^{h_2} \mathrm{MCP}_h\, V_h \geq s(\alpha^{\uparrow} + \alpha^{\downarrow}) + s(h_2 - h_1 + 1)\,\omega + \beta \sum_{h=h_1}^{h_2} V_h \tag{4}$$

[1] $s = 0$ implies bid rejection and $s = 1$ implies selection

2) Stepped Marginal Cost (FAK Steps): This bid structure is generalization of the one discussed above. In this scheme bidder can give his fixed cost along with minimum and maximum volume between which he can deliver, if his bid is selected. In addition, to this he can give price per unit volume at various levels of volumes. If variable price is independent of volume delivered, we arrive back to the earlier model. Such a scheme has been demonstrated in table below. Volumes tabulated here are incremental.

Fixed Cost			Volume	
Start Up	Shut Down	Running	Minimum	Maximum
$\alpha^{\uparrow}$	$\alpha^{\downarrow}$	ω	V_{min}	V_{max}

Price	β_1	β_2	....	β_m
Volume	V_1^b	V_2^b	....	V_m^b

Constant Volume Schedule: For a block bid over a period of h_1 to h_2 under this scheme, let us introduce

- $V_i \in \mathcal{R}^+$ volume variable scheduled for each price step, i.e, $i \in \{1, 2, \cdots, m\}$.
- $V \in \mathcal{R}^+$ to represent net volume scheduled.
- $s_i \in \mathcal{B}$ to represent selection of i^{th} bid step.
- $s \in \mathcal{B}$ to model overall selection of bid, whether full or partial.

Then, following constraints model financial requirements of the generator

- Volume scheduling constraint
  - If bid is not selected then scheduled volume $V = 0$ and if selected then $V_{min} \leq V \leq V_{max}$. Following relation captures this criteria,
$$sV_{min} \leq V \leq sV_{max} \tag{5}$$
  - Scheduled volume will be sum of volume scheduled from each step
$$V = \sum_{i=1}^{m} V_i, \quad \forall i \in \{1, 2, 3, \ldots, m\} \tag{6}$$
  - Corresponding to each step, scheduled volume will lie between 0 and maximum limit of the step V_i^b, provided that this step is selected. If a step is not selected, then this mini-schedule will be 0.
$$0 \leq V_i \leq s_i V_i^b, \quad \forall i \in \{2, 3, \ldots, m\} \tag{7}$$
  - Higher order step can be considered for selection, if previous order step has been filled completely
$$s_i \leq \frac{V_{i-1}}{V_{i-1}^b}, \quad \forall i \in \{2, 3, \ldots, m\} \tag{8}$$
  - If bid is selected, then lowest step should have been selected.
$$s = s_1 \tag{9}$$
- Minimum cost recovering constraint
  - If a bid is not selected then there is no cost to be recovered, and,
  - If a bid is selected with scheduled volume being V, then minimum cost to be recovered is sum of fixed cost, fixed running cost and cost arising out of marginal price and volume delivered. Marginal cost (Γ) is calculated as follows
$$\Gamma = \beta \sum_{i=1}^{m} V_i$$

where, β marginal price of last volume step being selected, which implies β is variable and hence, expression for Γ is not being modelled linearly. To represent this cost component we develop following linear model:

$$\begin{aligned} -\left(1-(s_i - s_{i+1})\right) M \leq \Gamma - \beta_i \sum_{i=1}^{m} V_i \\ \leq \left(1-(s_i - s_{i+1})\right) M \\ \forall i = 1, 2, m-1 \end{aligned} \tag{10}$$

$$-\left(1-s_m\right) M \leq \Gamma - \beta_m \sum_{i=1}^{m} V_i \leq \left(1-s_m)\right) M \tag{11}$$

$$-M \sum_{i=1}^{m} s_i \leq \Gamma \leq M \sum_{i=1}^{m} s_i \tag{12}$$

To understand the effect of above model, let us assume that step $k < m$ is selected. In such a scenario $s_1 = s_2 = \cdots = s_k = 1$ and $s_{k+1} = s_{k+2} = \cdots = s_m = 0$. Now, from eqn 10 for $l < k$, $s_l = s_{l+1}$. Therefore, $s_l - s_{l+1} = 0$ and hence, lower and upper bound on $\Gamma - \beta_i \sum_{i=1}^{m} V_i$ comes out to be $-M$ and M, and hence this constraint becomes ineffective. However, for $l = k$, we have $s_k - s_{k+1} = 1$ and hence, both lower and upper bound on $\Gamma - \beta_k \sum_{i=1}^{m} V_i$ comes out to be 0 and hence, $\Gamma = \beta_k \sum_{i=1}^{m} V_i$ is enforced. If all the steps are selected, then only eqn 11 will be effective to enforce $\Gamma = \beta_m \sum_{i=1}^{m} V_i$. Eqn 12 ensures that if none of the step is selected, then Γ is forced to take the value of 0.
Thus, we can model minimum income criteria as follows:

$$\begin{aligned} V \sum_{h=h_1}^{h_2} \mathrm{MCP}_h \geq & s(\alpha^{\uparrow} + \alpha^{\downarrow}) + s(h_2 - h_1 + 1)\,\omega \\ & + (h_2 - h_1 + 1)\,\Gamma \end{aligned} \tag{13}$$

Variable Volume Schedule: Under this mode of operation, we have to make slight adjustment and introduce volume, step-volume and step selection variables for each time slot $h \in \{h_1, h_1 + 1 \cdots, h_2\}$. Following similar steps as while modelling constant volume schedule model, we will arrive at following set of relations:

$$sV_{min} \leq V_h \leq sV_{max} \tag{14}$$
$$V_h = \sum_{i=1}^{m} V_i^h \tag{15}$$
$$0 \leq V_i^h \leq s_i^h V_i^b \tag{16}$$
$$s_i^h \leq s_{i-1}^h, \quad \forall i \in \{2,3,\ldots,m\} \tag{17}$$
$$s = s_1^h \tag{18}$$

$$\sum_{h=h_1}^{h_2} \mathrm{MCP}_h V_h \geq s(\alpha^{\uparrow} + \alpha^{\downarrow}) + s(h_2 - h_1 + 1)\,\omega \quad + \sum_{h=h_1}^{h_2} \Gamma_h \tag{19}$$

where, marginal cost pertaining to h^{th} hour (Γ_h) is derived as discussed earlier

(20)

3) Stepped Marginal Cost (FOK Steps): Bid structure is very much similar to earlier discussed model with the difference that each step is *indivisible*. This type of specification will benefit those generators, which can change volume only in steps.

Constant Volume Schedule: For a block bid over a period of h_1 to h_2 under this scheme, let us introduce

- $V_i \in \mathcal{R}^+$ volume variable scheduled for each price step, i.e, $i \in \{1, 2, \cdots, m\}$.
- $V \in \mathcal{R}^+$ to represent net volume scheduled.
- $s_i \in \mathcal{B}$ to represent selection of i^{th} bid step.
- $s \in \mathcal{B}$ to model overall selection of bid, whether full or partial.
- $\zeta_i \in \mathcal{R}^+$ variable to model value obtained from market through step, i.e, $i \in \{1, 2, \cdots, m\}$.

Then following constraints models finance of the generator

- Volume scheduling constraint
  - If bid is not selected then scheduled volume $V = 0$ and if selected then $V_{min} \leq V \leq V_{max}$. Following relation captures this criteria,
$$sV_{min} \leq V \leq sV_{max} \tag{21}$$
  - Scheduled volume will be sum of volume scheduled from each step
$$V = \sum_{i=1}^{m} V_i, \quad \forall i \in \{1,2,\ldots,m\} \tag{22}$$
  - Each step volume if not selected will result in volume to be delivered to be 0, otherwise full volume will be scheduled. Thus,
$$V_i = s_i V_i^b \tag{23}$$
  - Higher order step can be considered for selection, if previous order step has been filled
$$s_i \leq s_{i-1} \quad \forall i \in \{2,3,\ldots,m\} \tag{24}$$
  - If bid is selected, then lowest step should have been selected.
$$s = s_1 \tag{25}$$
- Minimum cost recovering constraint
  - If bid step is not selected then there is no corresponding value earned, i.e. $\zeta_i = 0$ but if it is selected then since full step will be scheduled, value earned will be product of corresponding volume with sum of MCPs from h_1 to h_2. Above mentioned constraint is modelled as follows
$$0 \leq \zeta_i \leq s_i M \tag{26}$$
$$-(1 - s_i)M \leq \zeta_i - V_i^b \sum_{h=h_1}^{h_2} \mathrm{MCP}_h \leq (1 - s_i)M \tag{27}$$
  - Minimum cost to be recovered comes out to be 0 if bid is not selected, else it is sum of start up, shut down, fixed running cost and volume delivery cost arising out of marginal cost. Hence,
$$\sum_{i=1}^{m} \zeta_i \geq s(\alpha^{\uparrow} + \alpha^{\downarrow}) + s(h_2 - h_1 + 1)\,\omega + (h_2 - h_1 + 1)\,\Gamma \tag{28}$$

Variable Volume Schedule: For a block bid over a period of h_1 to h_2 under this scheme, let us introduce

- $V_i^h \in \mathcal{R}^+$ volume variable scheduled for each price step and each time slot
- $V_h \in \mathcal{R}^+$ to represent net volume scheduled, for h^{th} time slot
- $s_i^h \in \mathcal{B}$ to represent selection of i^{th} bid step.
- $s \in \mathcal{B}$ to model overall selection of bid, whether full or partial.
- $\zeta_i^h \in \mathcal{R}^+$ variable to model value obtained for i^{th} step in h^{th} hour

Following similar steps as in constant volume schedule, we will arrive at following formulation

$$sV_{min} \leq V_h \leq sV_{max} \tag{29}$$
$$V_h = \sum_{i=1}^{m} V_i^h \tag{30}$$
$$V_i^h = s_i^h V_i^b \tag{31}$$
$$s_i^h \leq s_{i-1}^h, \quad \forall i \in \{2,3,\ldots,m\} \tag{32}$$
$$s = s_1^h \tag{33}$$
$$0 \leq \zeta_i^h \leq s_i^h M \tag{34}$$
$$-(1 - s_i^h)M \leq \zeta_i^h - V_i^h \mathrm{MCP}_h \leq (1 - s_i^h)M \tag{35}$$

$$\sum_{h=h_1}^{h_2} \sum_{i=1}^{m} \zeta_i^h \geq s(\alpha^{\uparrow} + \alpha^{\downarrow}) + s(h_2 - h_1 + 1)\,\omega + \sum_{h=h_1}^{h_2} \Gamma_h \tag{36}$$

B. Modelling of Term Contributing to Social Welfare

For all the structure discussed, right hand term of inequations modelling minimum income criteria will form the contribution term towards social welfare with negative sign. For example for the structure with constant marginal cost and constant volume, discussed in section IV-A.1, following term will be added to social welfare:

$$-\left(s(\alpha^{\uparrow}+\alpha^{\downarrow})+s(h_2-h_1+1)\,\omega+(h_2-h_1+1)\beta V\right)$$

C. Modelling Ramping Cost

Whenever, generator has to ramp (up or down) to shift from one volume level to another, some fuel might be wasted and hence cost needs to be recovered. Till now we have not accounted for this cost component. However, this factor cannot be ignored particularly in bid structure allowing volume to vary from one hour to another. We will assume that ramping cost (up and down) is proportional to change in volume schedule. Thus,

$$C^{ramp}=\gamma^{\uparrow}(V_h-V_{h-1})\quad \text{if } V_i>=V_{i-1}\text{, i.e. ramping up}$$
$$C^{ramp}=\gamma^{\downarrow}(V_{h-1}-V_h)\quad \text{if } V_{i-1}>=V_i\text{, i.e. ramping down}$$

Here, $\gamma^{\uparrow}$ is ramping up cost by per unit volume, and $\gamma^{\downarrow}$ is cost for ramping down by per unit of volume.

Constant Volume Schedule: Under constant volume operation, if ramping cost has to be modelled, only change will be over the right hand term on minimum income criteria. More precisely, term $(\gamma^{\uparrow}+\gamma^{\downarrow})V$ has to be added to the expression representing minimum cost to be recovered (minimum income). As for example eqn 2, modelling minimum cost to be recovered under fixed marginal cost mechanism, will be modified as

$$V\sum_{h=h_1}^{h_2}\mathrm{MCP}_h \geq s(\alpha^{\uparrow}+\alpha^{\downarrow})+s(h_2-h_1+1)\,\omega + (h_2-h_1+1)\beta V+(\gamma^{\uparrow}+\gamma^{\downarrow})V \quad (37)$$

Remark 2. *Because of the objective to maximize social-welfare, each of C_h^{ramp} will be pushed down as much as possible, and hence, will attain tighter of the bounds.*

Variable Volume Schedule: Irrespective of whether model is fixed and variable or fixed and marginal, modelling ramp is same. Let us define, variable C_h^{ramp}, as cost of ramping from time slot $h-1$ to h. Thus, considering bid for a period of h_1 to h_1, following condition holds,

$$C_h^{ramp}\geq\gamma^{\uparrow}(V_h-V_{h-1})\quad\forall h\in\{h_1+1,h_1+2,\cdots,h_2\} \quad (38)$$

$$C_h^{ramp}\geq\gamma^{\downarrow}(V_{h-1}-V_h)\quad\forall h\in\{h_1+1,h_1+1,\cdots,h_2\} \quad (39)$$

$$C_{h_1}^{ramp}=\gamma^{\uparrow}V_{h_1} \quad (40)$$

$$C_{h_2+1}^{ramp}=\gamma^{\uparrow}V_{h_2} \quad (41)$$

If $V_h>V_{h-1}$, eqn 38 gives tighter bound on C_h^{ramp}, whereas eqn 39 gives same for the case of $V_{h-1}>V_h$. Now add this variable to minimum income expression. Hence, for the case of fixed and marginal cost structure, corresponding expression (eqn 4) will be modified as

$$\sum_{h=h_1}^{h_2}\mathrm{MCP}_h\,V_h \geq s(\alpha^{\uparrow}+\alpha^{\downarrow})+s(h_2-h_1+1)\,\omega + \beta\sum_{h=h_1}^{h_2}V_h+\sum_{h=h_1}^{h_2+1}C_h^{ramp} \quad (42)$$

Similar relation follows for other models as well.

htb

TABLE II
BASE CASE SAMPLE DATA

	Buy		Sell		Block Sell	
Hr	Price	Volume	Price	Volume	Price	Volume
1	700	100	350	50	300	100
	600	150	380	150		
	550	200	—	—		
2	700	100	200	50		
	600	200	210	150		
	550	200	—	—		

V. Case Studies

A. Base Case: Normal Block Bids

Table II lists out data received for 2 hour market. On performing bid matching, it is observed that

1) Block bid is unable to clear,
2) Both sell and buy bid clears to 150 of volume for both the hours,
3) MCP for first hour comes out to be 575 and for second it is 600, and,
4) Total traded volume is 300 with net social welfare of 113500.

B. Case I: Stepped Block Bid for Flexibility

Let us assume that block bid came with a figure of 300 for 100 unit volume by the fact that its start up and shut down cost are both 20,000, and marginal cost of 100 when delivering volume of 100. Hence, for two hour operation, it has total cost of $(20,000+20,000)+2\times(100\times100)=600,000$. Hence, it requires average MCP of $\frac{600,000}{2\times100}=300$. However, suppose it can operate at two voltage levels of, one being 50 and other being 100. If this trader bid in this format (using stepped bid option), then bid matching process results in following observation:

1) Block bid is able to schedule total of 50 units of volume,
2) Buy bid schedules to 200 in both the hours and sell bid to 150,
3) MCP for first hour comes out to be 475, while for second it is observed to be 600, and,
4) Total traded volume in this case is 400 and net social welfare is 121000.

C. Case II: Variable Schedule for Block Bid

In this case we allow block bid to change its scheduled between both the hours. In this case it is observed that block bid is able to trade more in first hour where it is able to sell complete 100 unit of volume. MCPs comes out to be 380 and 470 with social welfare now being 135000.

D. Case II: More Competition

In this case seller (hourly) drops his price for hour 1. He bids price of 300 for total volume of 150. In hour 2, he introduced one more level of bidding, where he is willing to trade for 200 unit of volume, provided he gets price of 350.

Under this condition, block bid is unable to make any trade. Though, social welfare has increased to 136500 (due to low price by seller), traded volume comes down to 350.

E. Case III: Block Bid More Competitive

In response to above competition, block bidder observes that he can sustain with marginal price of 50 for first 50 unit of volume. However, if it is asked to deliver 100 unit of volume, its marginal price remains 100.

In this case block bids clears 50 unit of volume in both the hours, with social welfare being same at 136500, but with traded volume being 400.

VI. Conclusions

In this paper, we have developed new bid structures as alternative to block bids. Central notion behind each of these structure is ability to specify various cost components, namely, start-up, shut-down, ramping, running and volume dependent variable price. Possibility of block bid varying its volume is also explored and modelled in the structure. Case studies demonstrates that such a structure allows block bidder to come up with more competitive price. Also number of block bids being rejected paradoxically decreases. It is expected that incorporation of proposed block bid structures will lead to more volumes being scheduled. However, more thorough investigation is required to establish any such relation.

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Appendix I
Linearizing Quadratic Term in Minimum Income Expression

In expressions modelling minimum income constraint, we have encountered terms like $V \sum_h \mathrm{MCP}_h$ or $\sum_h V_h \mathrm{MCP}_h$. Since, both volume and MCP terms are variable, they cannot be used directly in ILP model. Hence, we develop linear approximation of the same. We will present this exercise for $V\,\mathrm{MCP}$. V can be appropriately replaced by V_h or kept V. Similarly, MCP by $\sum_h \mathrm{MCP}$ of MCP_h. Let us assume that V can be varied between V^{min} to V^{max} with a resolution of ΔV. Let $V^{max} - V^{min} = n\Delta V$, where n is an integer. Define integer m, such that $m = \lfloor \log_2 n/2 \rfloor + 1$. Hence, any value between V^{min} and V^{max} can be represented by following expression,

$$V = S_s V^{min} + \sum_{g=1}^{m} s_g 2^{g-1} \Delta V$$

where, s_g represents m switches to be selected appropriately, and S_s is block selection switch.

- Income criteria from first block of V^{min}

$$-(1-S_s)M \leq C_s^0 - V^{min} \sum_{k=k1}^{k2} MCP(k) \leq (1-S_s)M$$

$$-S_s M \leq C_s^0 \leq S_s M$$

- Income criteria through each delta block

$$-(1-s_g)M \leq C_s^g - (2^g - 1)\Delta V \sum_{k=k1}^{k2} MCP(k) \leq (1-s_g)M$$

$$-s_g M \leq C_s^g \leq s_g M$$

- Any of this delta block is eligible for selection only if main block has been selected

$$s_g \leq S_s$$

- Net income

$$C_s = \sum_{g=0}^{n} C_s^g$$

Thus, in expression modelling minimum income, right hand term ($V \sum_h \mathrm{MCP}_h$ or $\sum_h V_h \mathrm{MCP}_h$), can be replaced by C_s.

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Facilitating Emission Trade within Power Exchange: Development of Conceptual Platform

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***Abstract*— Electricity sector is one of the major contributor of emission. Hence, any policy which restricts emission level will have significant impact on its functioning. As a consequence, electricity traders will have to actively participate in emission market. What it means is that electricity traders will have to trade in two separate markets, namely power and emission (or carbon). However, to be able to derive maximum benefit, trader should be able to accurately forecast prices in either of the markets. Alternatively, we propose a new scheme where emission trading is facilitated within power exchange (PX). This not only provides single trading platform for the traders but also ensures that maximum benefit is achieved for individually as well as collectively by utilizing available carbon credits optimally.**

***Index Terms*— Power Exchange, Carbon Trading, Social Welfare Maximization, Market Equilibrium**

I. Introduction

KYOTO protocol established caps on the maximum quantity of greenhouse gas emission permitted for Annex I developed and developing countries [1, pg 35]. Internal quotas are set by these countries on emissions as a result of local business and other organizations, generally termed as 'operators'. Each operator is allocated carbon credits, where each credit gives the owner the right to emit one metric ton of CO_2E. The GWP (Global Warming Potential) factors are used to convert each of the five gases (like methane, for example) that are not CO_2 into tonnes of CO_2 equivalent (CO_2E), which is the standard of trading. Those who have unutilized quotas can sell the same to those who feel the need of additional allowances. Such trading occurs privately or in the open market [1]. In fact, such trading can also occur between two nations. In effect, this mechanism provides an incentive for adoption of green technologies as doing so will bring down emission level and hence, spare allowance can be sold in market to generate additional revenue.

Electricity sector is a major contributor towards emission and hence, such a policy restricting emission level will have major impact on it. This, in turn, means that electricity traders will have to participate actively in emission market. In fact, electricity market by itself may provide considerable volume in carbon trade.

Under emission constrained environment, electricity traders have to take the cost of emission into account while putting up bids/offers. Sometime it may be even profitable to sell owned allowances. An electricity seller may like to sell carbon credits due to one of the following reasons:

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1) Generating capability being not enough to exhaust allocated credits i.e. surplus carbon credits,
2) Inability to get adequate amount of schedule due to low demand or being costlier generation, and,
3) Price of selling credits being more favourable than price of selling electricity using these credits.

Similarly, one may like to purchase carbon credit if one feels that purchasing additional credits enable scheduling units, which otherwise could not have been. Moreover, profit acquired out of these additional schedules is more than what have been spent on purchasing credits.

Currently, separate markets exist for power and carbon trading. As a result, trader has to put up his offers in power market judiciously. It has to take possible price, at which trader may be able to purchase additional carbon credits, in consideration. Therefore, trader should be able to forecast price on either of the market accurately. Situation can become more complex for block bidders/offers, who even after knowing the price may not be certain whether they will get schedule or not.[1] In contrast, in our work we propose to couple power and carbon markets which will make such accurate forecasting need almost redundant. Trader has to only worry about how corresponding generation capability is valued or what utility one can associate with energy consumption. Proposed market mechanism by itself will take care of allotting appropriate credits to the traders at optimal price. This results, as demonstrated by case studies, in better utilization of emission allowances.

Some work have been reported on coupling emission constraints with unit commitment. In [2], authors have applied Lagrangian-relaxation-based algorithm, wherein emission is considered as a second objective function with a weighting factor. This approach, actually tries to minimize net emission rather than limiting it to a predefined value. Similar technique have been applied in [3], but here certain limit is imposed on net emission. In [4], authors have used simulated annealing to solve unit commitment problem, while the emission constraints are taken into consideration by counting the cost of purchasing additional emission allowances in the case that the total system emissions exceed a predefined maximum limit. This approach tries to find an optimal trade-off between the total cost of the system and the enforcement of the emission constraint. An iterative methodology has been proposed in [5] which accounts for network constraints as well. In all these cases, emission constraint is imposed globally and hence, no trading of carbon credits takes place. The work in [6] has formulated this problem as an instance of mixed integer non-

[1] Block bids may be rejected paradoxically.

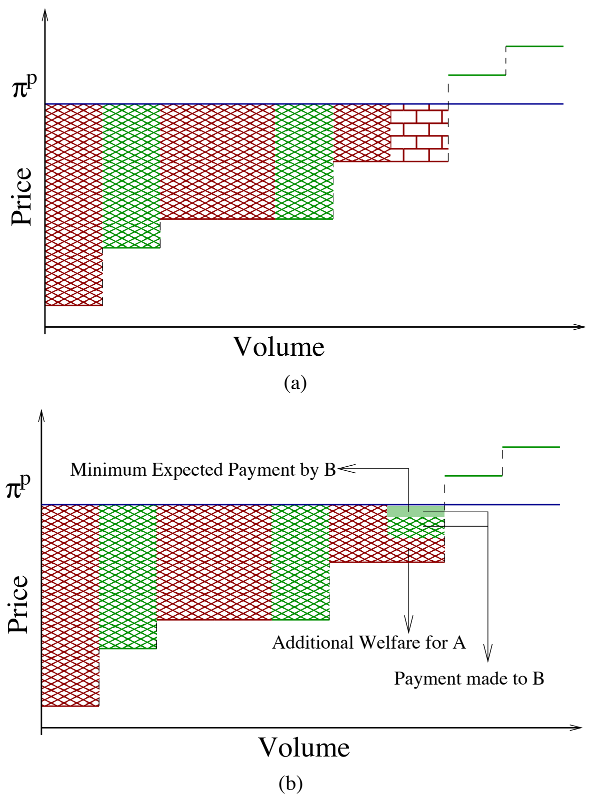


Fig. 1. Effect of emission constraint on Scheduling and Social Welfare

linear programming problem. Here, authors have accounted the possibility that a trader can buy/sell deficit/surplus emission allowances in separate emission market.

As far as our investigation indicate, there is no prior work reported, which has attempted to couple such a constraint within power exchange. Moreover, this work differs in the sense that while emission constraint is honoured globally, each trader also have certain limits to be obeyed. However, this limit, can be either increased/decreased by buying/selling carbon credits from/to other traders.

We begin with a motivation example in section II to bring out the benefit of facilitating trading power and carbon credits under single platform. Thereafter, we develop conceptual understanding on the market behavior within the proposed mechanism and also extend the definition of social welfare and equilibrium prices in section III. Results are presented in section IV to bring out the distinction when compared with normal market after which paper is concluded in section V.

II. Motivation Example

Fig 1 represents a simplified scenario. There is one demand bid with single step, whereas on supply side two traders, say trader A (shown in red color) and trader B (represented by green color). Both sellers have put up offers in multistep. In absence of emission constraint all red steps are cleared whereas two steps in green goes out of the market.

Now suppose that generators possessed by trader A pollutes high. Consequently, he may have to curtail his generation to a lower schedule even though his price is well below market price. As a result he looses part of surplus, marked in brick

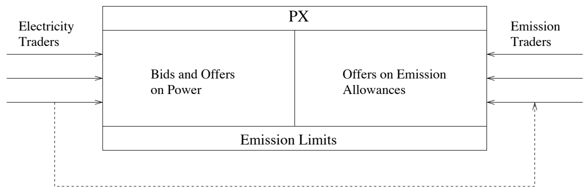


Fig. 2. Conceptual Illustration of Emission Trading within Power Exchange

pattern in figure 1(a). Now since, trader B has enough spare carbon credits, either due to lack of schedule or due to less polluting units, some of his credits may be transferred to trader A. However, this transfer is possible provided minimum sell price expected by trader B ensures that trader A makes additional profit over restricted schedule.

To develop clearer understanding, let us suppose to generate 1 MWh of energy (or 1 MW of power for 1 hour), A's generator emits k units of pollutants. Let us assume that market price for electricity and emission trading comes out to be π^p and π^e respectively. Let unscheduled step have bid price of p. Also, trader B might have lower limit on sell value of carbon credits, say p^l. On scheduling this step, trader A will earn surplus of $\pi^p - p$ per unit of volume. However, trader has to also spend $k\pi^e$ for each unit of additional volume being scheduled. Now, transfer of credit is acceptable to trader A if incremental expenditure (on purchasing credits) is less than incremental surplus. Hence, if there exists π^e such that, $p^l \leq \pi^e$ and $\pi^p - p \geq k\pi^e$, transfer of credits can take place.

Figure 1(b) captures the effect of credit transfer. As shown in the figure, trader A is able to schedule complete volume at this last step as well. However, he loses certain surplus due to expenditure incurred on paying trader B to buy additional credits.

III. Proposed Mechanism

In [6], authors have modelled emission sales and purchase from separate spot market in optimal unit commitment. Generators in addition to cost curve also submit estimate on emission allowances price for buy and sell at which, if required, trader can obtain additional credits or sell spare ones. The objective of this model is to minimize net generation cost, which accounts for cost curve, start-up costs and costs associated with buying and selling emission allowances.

This model can be easily applied to PXs' scheduling framework as well, though with few additional/modified constraints. However, in proposed scheme, we follow different methodology. We capture possibility of emission trade among electricity traders as a part of PX activity. Under this mechanism, traders, in addition to their price-volume relation, declares emission limits that they are willing to utilize over the whole day. They also declare minimum price at which they will be willing to sell spare allowances. This model even permits pure emission seller to participate in the market. Whether to allow such participation or not is left to PX's discretion. Figure 2 captures the concept of proposed mechanism.

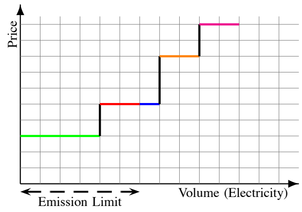


Fig. 3. Example Aggregated Supply Curve

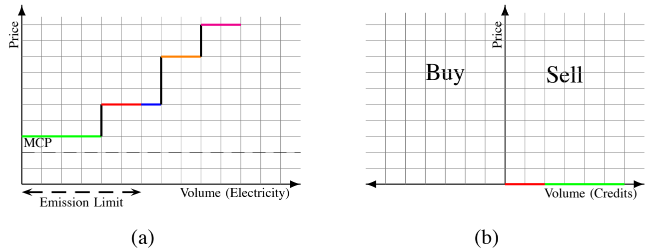


Fig. 4. Effect on Emission Utility with MCP below first step

A. Inferred Emission Utility on the Basis of Power Market Clearing Prices

In this section, conceptual understanding is developed on the relation between clearing prices in power market and utility of emission credits. More precisely, through simple example, it is demonstrated that *significance/importance* that trader will associate with emission rights will have direct correlation with prices at which power market clears. In short, it is established that if lower prices are prevalent in power market, then appetite for carbon credits diminishes, whereas with higher price priority will reverse.

Figure 3 represents an example supply offer curve from a trader. Also, marked is the limit on generation capability due to limit on emission allowances held by him. We assume that emission factor remains same irrespective of amount of power being delivered. We also make simplified assumption that emission allowances by itself has no value for the trader, which means, if he is unable to utilize the credits, he is willing to sell them for free. This restriction can be easily relaxed as explained in remark 1.

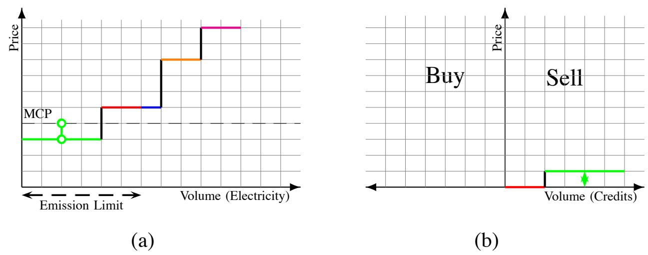


Fig. 5. Effect on Emission Utility with MCP between first and second step

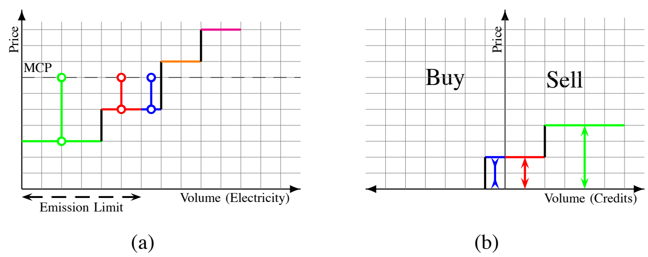


Fig. 6. Effect on Emission Utility with MCP between second and third step. Inward arrows indicates price should be less than limit for corresponding trade to be acceptable while outward arrows represents greater price.

We now consider MCP at various levels and its impact on utility that is perceived out of emission credits.

MCP below first step:
Since, trader cannot schedule any amount of power, he can put all his credits for emission trade with price zero as shown in fig 4(b).

MCP between first and second step:
Under this scenario, second step cannot be scheduled at all and hence, corresponding allowances can be put up as offer with zero limit price. Trader will prefer scheduling first step, unless emission price is so high that revenue earned there is more than the surplus gained in power market. Consequently, he can put up offer for this part of emission allowances at an appropriate price. Thus, if emission constant is k, offer price is p and MCP is π_h^p, then trader will put up an offer on credits with limit price of $\frac{\pi_h^p - p}{k}$ as shown in fig 5(b).

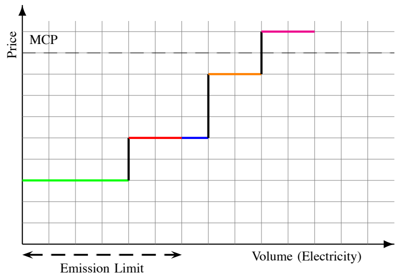
MCP between second and third step:
In this case, trader can schedule both first and second step profitably. However, second step can be scheduled partially due to emission constraint. As in earlier case, trader can derive offer prices on emission credits corresponding to both these steps. Additionally, he will like to schedule remaining part of second step provided he can acquire additional credits at cost less than the surplus which trader will gain through corresponding trade in power market. Thus, trader can put up appropriate bid for emission purchase as indicated in fig 6(b). In similar vein, curve on emission trade can be derived for other MCPs.

Remark 1. *In the example worked out above, we assumed that emission allowance by itself has no value for trader. However, if trader associates certain minimum value, then it can be accounted by simply shifting the curve by that value while selling.*

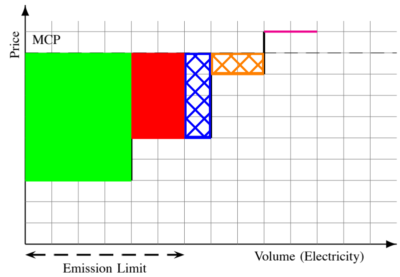
B. Relation of Surplus Maximization Strategy with Clearing Prices on Power and Emission Trading

It was observed that different MCPs in power market leads to different perception on emission allowance utility from a trader's perspective. Next, using this relation, we develop understanding on the strategy that should be adopted by a trader so as to maximize his surplus for a given set of prices on both power and emission.

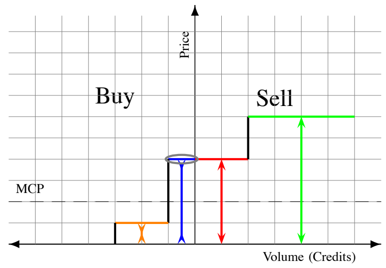
In fig 7(a), the example discussed earlier (fig 3) is revisited, where MCP in power market lies between third and fourth offer step. Consequently, trader could have scheduled each of the first three steps due to positive surplus gained in each of them. However, constraint on emission means that generation has to be backed down resulting in clearing of first step and partially second step. This is indicated in fig 7(b), where surplus possible within available credits are marked in solid colors while surplus lost is marked in cross-hatched pattern.



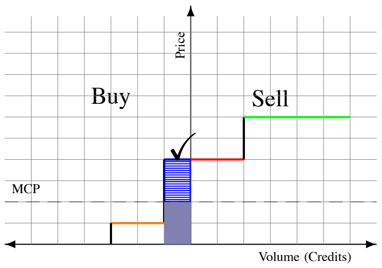
(a) Example offer curve from a trader with corresponding emission limit. MCP is also marked.



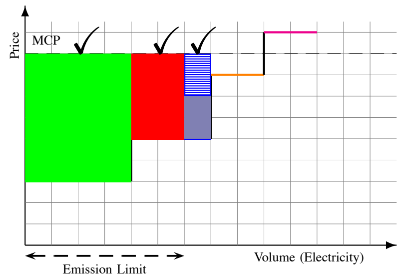
(b) Solid blocks are surplus that can be gained within available emission limits and cross-hatched indicates that which can be gained if additional credits are available



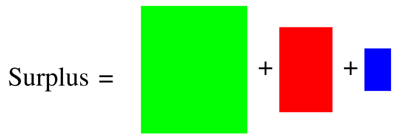
(c) Emission trading curve, with MCP in emission market is as marked. At this MCP, buying credits corresponding to blue step is profitable for the trader.



(d) Semi-filled block is the cost incurred by trader and solid block is the surplus gained in addition to green and red.

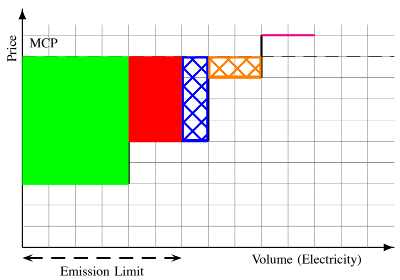


(e) Along with red and green steps, blue steps can be scheduled due to additional credits procured from emission market. However, orange step cannot be scheduled as emission price is not that favourable.

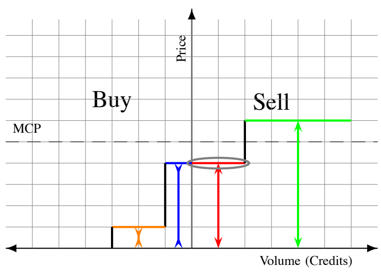


(f) Net surplus after accounting trade in both the markets.

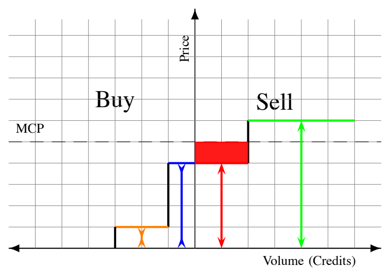
Fig. 7. Maximizing trader's surplus considering prices both in power and emission market: Low price in emission market



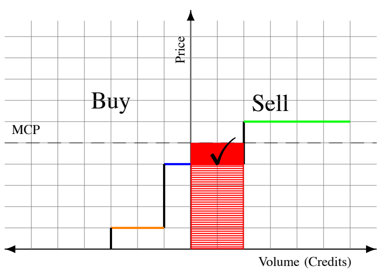
(a) At given MCP, trader can schedule first two steps profitably and next two steps if emission credits can be procured in appropriate price.



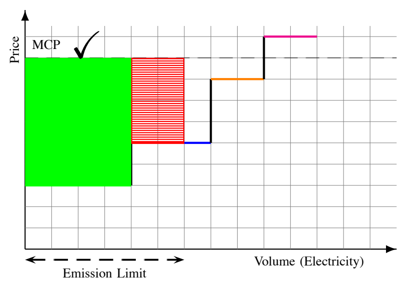
(b) Emission curve inferred in response to MCP in power market. Selling credits corresponding to second step is observed to be more profitable due to higher emission price.



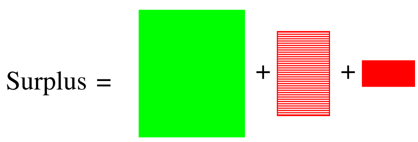
(c) Spare credits that can be generated after backing of second generation step. The red rectangular block is additional surplus on selling these credits as compared to what could be gained by scheduling second step and consuming them.



(d) Surplus made out of backing generation and selling corresponding credits.



(e) Only first step is scheduled, second step is backed down.



(f) Net surplus after accounting trade in both the markets.

Fig. 8. Maximizing trader's surplus considering prices both in power and emission market: High price in emission market

If this MCP was known a-priori, supplier would have put emission trading curve as shown in fig 7(c). In this curve, left part represents bids on emission purchase and right component models offers on sale. If trader can procure small amount of additional credits, he will be able to schedule part of blue step. However, for such a trade to be possible, price on emission should be less than incremental surplus gained for each unit of credits. Hence, he comes with the corresponding price for the same and also amount of volume which he can purchase (which is limited by maximum volume in blue part). Next is third step which has even less amount of surplus and hence leads to lower value being associated with credits as shown in figure.

It is also possible that trader could back down his generator provided prices on emission is more than incremental surplus gained out of the step being backed down. Thus, two such steps forms the part of emission sell curve. Now, as shown in fig 7(c), if emission price turns out to be on lower side say somewhere in between first and second step of buy part of curve, trader will naturally purchase credits which will enable him to schedule blue part of generation completely as indicated in fig 7(e).

Net surplus, as indicated in fig 7(f), now has blue component which is combined effect of power and emission trading. As it is observed, part of surplus gained in power market is now paid to procure required credits.

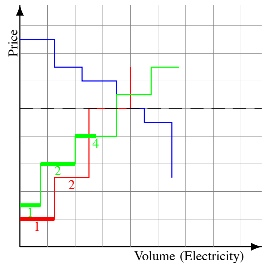
Now let us consider same example but with higher price on emission trading as shown in fig 8(b). As it can be observed, maximum benefit for trader will be in selling all the credits associated with scheduling of red part of offer. Doing so gives him additional surplus over what he was able to obtain by scheduling same part of generation. This additional benefit is marked as solid red coloured rectangle in fig 8(c). Net surplus, thus made out of overall trading is shown in fig 8(f). The middle component in this figure is the surplus that trader would have acquired if he had not backed down. Third component is additional benefit that trader gains by trading generated spare credits in market.

Remark 2. *In the proposed framework, the value of emission credits is derived from offer values and MCP in the electricity market. This leads to formation of a* sub-market *on emission, where sellers only provide minimum expected price on selling. Actual offers (sell) and bids (buy) on emission are implicitly modelled as function of electricity offers and corresponding MCP. A simultaneous solution of two markets leads to equilibrium scenario while maximizing social welfare which has component from both electricity as well as emission trading.*

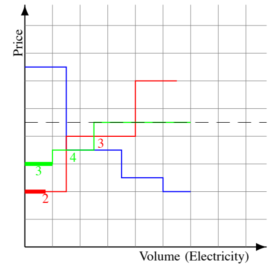
C. Market Equilibrium

In a market, *equilibrium* is said to exist if at the given MCP none of the traders have any incentive to move away from allocated schedule. These price(s) are referred as *equilibrium price(s)*. We extend this concept to the proposed scheme as follows:

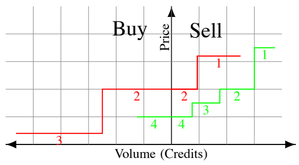
"A given set of prices and schedules on power and emission trading is said to establish market equilibrium, if at these MCPs (on both electricity and emission) one can come up with schedule as well as emission trade (along with corresponding price), maintaining supply-demand balance on both power and emission, to which none of the trader has any objection."



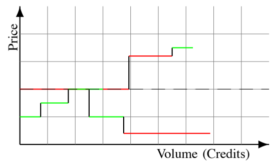
(a) First Hour Offers and Bids: Selected Offers at given MCP (considering emission limits) are Marked Thicker



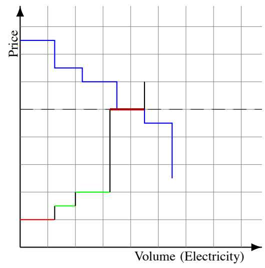
(b) Second Hour Offers and Bids: Selected Offers at given MCP (considering emission limits) are Marked Thicker



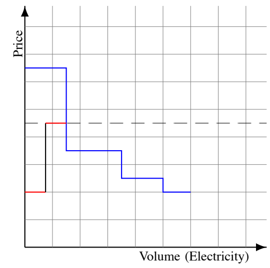
(c) Inferred Emission Utility Curve for both the Traders



(d) Aggregated Emission Curve: Buy Part Reflected on First Quadrant



(e) Adjusted Offer Curves for First Hour after Accounting for Emission Trade



(f) Adjusted Offer Curves for Second Hour after Accounting for Emission Trade

Fig. 9. Fictitious two hour market to demonstrate equilibrium with embedded emission trading mechanism

Figure 9 demonstrates this concept. In this example, a fictitious two hour market is considered with one consumer (in blue) and two suppliers (in red and green respectively referred as A and B). A has emission limit of 10 $MTCO_2E$ with emission factor being 1.25 $MTCO_2E/MWh$, while B can pollute up to 15 $MTCO_2E$, with his generators leading to 1 $MTCO_2E$ of emission for each MWh of energy generated. Each grid in the figure represents 4 MW of power (and hence 4 MWh of energy over 1 hour) on x-axis and 4 MU (MU stands of appropriate monetary unit) for price on y-axis On solving this problem, equilibrium prices are found to be 20 MU/MW for first hour and 18 MU/MW for second. We now explain how these prices lead to equilibrium. Provided prices are known, both the traders will schedule so as to maximize profit while honouring individual emission limits. This scheduled is indicated by thicker line-segments in fig 9(a) and 9(b). Note that as emission limit is across the entire scheduling period (in this case 2 hours), steps from both the hours will be ranked based upon their difference from corresponding MCP

TABLE I

TEST CASE CONSISTING OF 3 SELLERS AND 1 BUYER

	Offers/Bids as Strings of (Price,Volume)		Emission		
	Hour 1	Hour 2	L	F	V
S1	(2,7) (5,5) (10,8)	(6,6) (10,6)	12	0.8	3
S2	(2,13) (5,8) (7,8) (9.15)	(2,6) (8,6) (10,5) (12,3)	15	1.25	2
S3	(9,10) (11,15)	(4,2) (10,6) (15,6)	20	0.25	1
B1	(20,10) (18,7) (15,7) (10,14) (5,12)	(20,10) (15,8) (10,8) (5,4)	–	–	–

L=Limit; F=Factor; V=Value

(MCP – Offered Price); highest difference means first rank. Steps are then selected in this order till limit is exhausted or no more step is left. This ranking is marked in the figure itself. Hence, emission utility curve can be inferred on behalf of both the traders as shown in left part of fig 9(c), which is then aggregated (as shown in fig 9(d)). The intersection of buy and sell curve leads to clearing price of 8 MU/MTCO_2E and traded volume to be anywhere between 7 to 10 MTCO_2E, with buyer being A. As one will like to maximize the traded volume, we choose 10 MTCO_2E. Consequently, B has to back-down 10 MWh of generation and A has freedom to deliver 8 MWh of energy more over the period of two hour in any combination. Naturally, B will back-down that part of generation which brings him least surplus whereas A schedules those bringing him most surplus. Eliminating unscheduled part of generation curve and accounting for emission purchase on portion of A's curve representing additional schedule (due to emission trade), aggregated curves are plotted for each hour in fig 9(e) and 9(f). As it is observed, resulting intersection exactly at the MCPs assumed earlier. Repeating same exercise for other set of MCPs (say 24 MU/MW and 16 MU/MW), one can observe that final intersection will occur at some other price levels and hence non-equilibrium state.

IV. Results

We consider a simple test case with three sellers (S1, S2 and S3) and single buyer (B1) as shown in table I. Emission factor is assumed to be constant for each of the seller. S2 has cheapest offer and is also most polluting, whereas S3 is costliest but cleanest source of power supply. S1 lies in between the two in terms of both offered electricity price as well as pollution.

Three cases are considered; in *first* case emission limits are ignored while *second* one enforces emission limits but no trading whereas *third* case permits emission trading among participants. Table II summarizes overall results. As it is observed from this table, Case-I results in highest social welfare, which is on the line of expectations. However, resulting schedules means that S1 has to cover deficit of 2.4 units of emission credits while in case of S2 it is 32.5 units whereas S3, being unable to clear enough volume due to costlier generator(s), is left with 18 units of spare credits. Case-II, due to individual emission restrictions, means that generation has to be curtailed significantly by S1 and S2. This, in turn, allows S3 to inject more power, though not much. Consequently, net welfare reduces significantly. While S1 and S2, as expected, are found to exhaust emission credits, S3 is left with spare 15.5 units. Case-III, due to embedded emission trading, allows S1 and S2 to purchase appropriate amount of credits from S3. Social welfare as well as traded volume is boosted as compared to Case-II, but remains lower than Case-I. Emission credits are exhausted completely.

TABLE II

RESULTS ON TEST CASE IN TABLE I

			Case I	Case II	Case III
MCP	Hour 1		7	10	9.6875
	Hour 2		10	10	10.6875
Traded Volume	Hour 1	S1	12	11	12
		S2	26	6	17.1
		S3	0	10	8.9
		B1	38	27	38
	Hour 2	S1	6	4	6
		S2	12	6	6
		S3	8	8	6
		B1	26	18	18
Total Electricity Volume Traded			64	45	56
$\frac{E_{gen}}{E_{lim}+E_{buy}-E_{sell}}$		S1	$\frac{14.4}{12+0-0}$	$\frac{12}{12+0-0}$	$\frac{14.4}{12+2.4-0}$
		S2	$\frac{47.5}{15+0-0}$	$\frac{15}{15+0-0}$	$\frac{28.875}{15+13.875-0}$
		S3	$\frac{2}{20+0-0}$	$\frac{4.5}{20+0-0}$	$\frac{3.725}{20+0-16.275}$
Total Emission Credits Traded			–	–	16.275
Emission Price			–	–	3.75
Social Welfare			673	545	619.125

E_{gen} is generated emission while E_{lim} represents emission limits originally held. E_{buy} and E_{sell} respectively are emission rights purchased and sold.

V. Conclusions

This paper has developed concepts on embedding emission trader within participants in PX while carrying out power scheduling and providing single platform for power as well as carbon trading. Examples presented have demonstrated as how trader's perception towards the utility of emission credits changes with variation in electricity prices. Also, equilibrium prices have new dimension as now equilibrium has also to be established with respect to emission trading. Since emission limits are to be honoured across scheduling period, these prices are dependent, even while considering only hourly bids. Thus, this work has constructed a foundation for detailed mathematical model which captures traders' behaviour under proposed mechanism, so as to develop tool for computing optimal schedule.

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COMMISSION REGULATION (EU) 2015/1222

of 24 July 2015

establishing a guideline on capacity allocation and congestion management

(Text with EEA relevance)

THE EUROPEAN COMMISSION,

Having regard to the Treaty on the Functioning of the European Union,

Having regard to Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003 ([1]) and in particular Article 18(3)(b) and (5),

Whereas:

(1) The urgent completion of a fully functioning and interconnected internal energy market is crucial to the objectives of maintaining security of energy supply, increasing competitiveness and ensuring that all consumers can purchase energy at affordable prices. A well-functioning internal market in electricity should provide producers with appropriate incentives for investing in new power generation, including in electricity from renewable energy sources, paying special attention to the most isolated Member States and regions in the Union's energy market. A well-functioning market should also provide consumers with adequate measures to promote more efficient use of energy, which presupposes a secure supply of energy.

(2) Security of energy supply is an essential element of public security and is therefore inherently connected to the efficient functioning of the internal market in electricity and the integration of the isolated electricity markets of Member States. Electricity can reach the citizens of the Union only through the network. Functioning electricity markets and, in particular, the networks and other assets associated with electricity supply are essential to public security, to economic competitiveness and to the well-being of the citizens of the Union.

(3) Regulation (EC) No 714/2009 sets out non-discriminatory rules for access conditions to the network for cross-border exchanges in electricity and, in particular, rules on capacity allocation and congestion management for interconnections and transmission systems affecting cross-border electricity flows. In order to move towards a genuinely integrated electricity market, the current rules on capacity allocation, congestion management and trade in electricity should be further harmonised. This Regulation therefore sets out minimum harmonised rules for the ultimately single day-ahead and intraday coupling, in order to provide a clear legal framework for an efficient and modern capacity allocation and congestion management system, facilitating Union-wide trade in electricity, allowing more efficient use of the network and increasing competition, for the benefit of consumers.

(4) To implement single day-ahead and intraday coupling, the available cross-border capacity needs to be calculated in a coordinated manner by the Transmission System Operators (hereinafter 'TSOs'). For this purpose, they should establish a common grid model including estimates on generation, load and network status for each hour. The available capacity should normally be calculated according to the so-called flow-based calculation method, a method that takes into account that electricity can flow via different paths and optimises the available capacity in highly interdependent grids. The available cross-border capacity should be one of the key inputs into the further calculation process, in which all Union bids and offers, collected by power exchanges, are matched, taking into account available cross-border capacity in an economically optimal manner. Single day-ahead and intraday coupling ensures that power usually flows from low- price to high- price areas.

(5) The market coupling operator (hereinafter 'MCO') uses a specific algorithm to match bids and offers in an optimal manner. The results of the calculation should be made available to all power exchanges on a non-discriminatory basis. Based on the results of the calculation by the MCO, the power exchanges should inform their clients of the successful bids and offers. The energy should then be transferred across the network according to

([1]) OJ L 211, 14.8.2009, p. 15.

the results of the MCO's calculation. The process for single day-ahead and intraday coupling is similar, with the exception that the intraday coupling should use a continuous process throughout the day and not one single calculation as in day-ahead coupling.

(6) Capacity calculation for the day-ahead and intraday market time-frames should be coordinated at least at regional level to ensure that capacity calculation is reliable and that optimal capacity is made available to the market. Common regional capacity calculation methodologies should be established to define inputs, calculation approach and validation requirements. Information on available capacity should be updated in a timely manner based on latest information through an efficient capacity calculation process.

(7) There are two permissible approaches when calculating cross-zonal capacity: flow-based or based on coordinated net transmission capacity. The flow-based approach should be used as a primary approach for day-ahead and intraday capacity calculation where cross-zonal capacity between bidding zones is highly interdependent. The flow-based approach should only be introduced after market participants have been consulted and given sufficient preparation time to allow for a smooth transition. The coordinated net transmission capacity approach should only be applied in regions where cross-zonal capacity is less interdependent and it can be shown that the flow-based approach would not bring added value.

(8) A common grid model for single day-ahead and intraday coupling purposes representing the European interconnected system should be established to calculate cross-zonal capacity in a coordinated way. The common grid model should include a model of the transmission system with the location of generation units and loads relevant to calculating cross-zonal capacity. The provision of accurate and timely information by each TSO is essential to the creation of the common grid model.

(9) Each TSO should be required to prepare an individual grid model of its system and send it to TSOs responsible for merging them into a common grid model. The individual grid models should include information from generation and load units.

(10) TSOs should use a common set of remedial actions such as countertrading or redispatching to deal with both internal and cross-zonal congestion. In order to facilitate more efficient capacity allocation and to avoid unnecessary curtailments of cross-border capacities, TSOs should coordinate the use of remedial actions in capacity calculation.

(11) Bidding zones reflecting supply and demand distribution are a cornerstone of market-based electricity trading and are a prerequisite for reaching the full potential of capacity allocation methods including the flow based method. Bidding zones therefore should be defined in a manner to ensure efficient congestion management and overall market efficiency. Bidding zones can be subsequently modified by splitting, merging or adjusting the zone borders. The bidding zones should be identical for all market time-frames. The review process of bidding zone configurations provided for in this Regulation will play an important role in the identification of structural bottlenecks and will allow for more efficient bidding zone delineation.

(12) TSOs should implement coordinated redispatching of cross-border relevance or countertrading at regional level or above regional level. Redispatching of cross-border relevance or countertrading should be coordinated with redispatching or countertrading internal to the control area.

(13) Capacity should be allocated in the day-ahead and intraday market time-frames using implicit allocation methods, in particular methods which allocate electricity and capacity together. In the case of single day-ahead coupling, this method should be implicit auction and in the case of single intraday coupling it should be continuous implicit allocation. The method of implicit auction should rely on effective and timely interfaces between TSOs, power exchanges and a series of other parties to ensure capacity is allocated and congestion managed in an efficient manner.

(14) For efficiency reasons and in order to implement single day-ahead and intraday coupling as soon as possible, single day-ahead and intraday coupling should make use of existing market operators and already implemented solutions where appropriate, without precluding competition from new operators.

(15) The Commission, in cooperation with the Agency for the Cooperation of Energy Regulators (hereinafter the 'Agency') may create or appoint a single regulated entity to perform common MCO functions relating to the market operation of single day-ahead and intraday coupling.

(16) The development of more liquid intraday markets which give parties the ability to balance their positions closer to real time should help to integrate renewable energy sources into the Union electricity market and thus, in turn, facilitate renewable energy policy objectives.

(17) Day-ahead and intraday cross-zonal capacity should be firm to allow effective cross-border allocation.

(18) In order for the implicit auctions to take place Union-wide, it is necessary to ensure Union-wide price coupling process. This process should respect transmission capacity and allocation constraints and should be designed in a manner that allows for its application or extension across the entire Union and for the development of future new product types.

(19) Power exchanges collect bids and offers within different time-frames which serve as a necessary input for capacity calculation in the single day-ahead and intraday coupling process. Hence, the rules for the trading of electricity provided for in this Regulation require an institutional framework for power exchanges. Common requirements for the designation of nominated electricity market operators (hereinafter NEMOs) and for their tasks should facilitate the achievement of the aims of Regulation (EC) No 714/2009 and allow single day-ahead and intraday coupling to take due account of the internal market.

(20) Establishing single day-ahead and intraday coupling process requires cooperation between potentially competing power exchanges in order to establish common market coupling functions. That is why oversight and compliance with competition rules is of utmost importance regarding these common functions.

(21) Despite the creation of a reliable algorithm to match bids and offers and appropriate back-up processes, there may be situations where the price coupling process is unable to produce results. Consequently, it is necessary to provide for fallback solutions at a national and regional level to ensure capacity can still be allocated.

(22) Reliable pricing of transmission capacity should be introduced for the intraday market time-frame, reflecting congestion if capacity is scarce.

(23) Any costs incurred efficiently to guarantee firmness of capacity and to set up processes to comply with this Regulation should be recovered via network tariffs or appropriate mechanisms in a timely manner. NEMOs, including in performing MCO functions should be entitled to recover their incurred costs if they are efficiently incurred, reasonable and proportionate.

(24) Rules for sharing the common costs of single day-ahead coupling and single intraday coupling between NEMOs and TSOs from different Member States should be agreed before the implementation process starts in order to avoid delays and disputes due to cost sharing.

(25) The cooperation between TSOs, NEMOs and regulatory authorities is necessary in order to promote the completion and efficient functioning of the internal market in electricity and to ensure the optimal management, coordinated operation and sound technical development of the electricity transmission system in the Union. TSOs, NEMOs and regulatory authorities should exploit synergies arising from capacity allocation and congestion management projects contributing to the development of the internal market in electricity. They should draw on the experience gained, respect the decisions made, and use solutions developed as part of those projects.

(26) In order to ensure the close cooperation among TSOs, NEMOs and regulatory authorities, a robust, reliable and non-discriminatory Union governance framework for single day-ahead and intraday coupling should be established.

(27) The objective of this Regulation, namely the establishment of single day-ahead and intraday coupling, cannot be successfully achieved without a certain set of harmonised rules for capacity calculation, congestion management and trading of electricity.

(28) However, single day-ahead and intraday coupling should only be implemented stepwise, as the regulatory framework for electricity trade and the physical structure of the transmission grid are characterised by significant differences between Member States and regions. The introduction of single day-ahead and intraday coupling therefore requires a successive alignment of the existing methodologies on capacity calculation, allocation and congestion management. Single intraday and day-ahead coupling may therefore be introduced at a regional level as an intermediate step where necessary.

(29) Single day-ahead and intraday coupling require the introduction of harmonised maximum and minimum clearing prices that contribute to the strengthening of investment conditions for secure capacity and long-term security of supply both within and between Member States.

(30) Given the exceptionally high degree of complexity and detail of the terms and conditions or methodologies needed to fully apply single day-ahead and intraday coupling, certain detailed terms and conditions or methodologies should be developed by TSOs and NEMOs and approved by the regulatory authorities. However the development of certain terms and conditions or methodologies by TSOs and power exchanges and their subsequent approval by regulatory authorities must not delay the completion of the internal electricity market. Thus, it is necessary to include specific provisions on cooperation between TSOs, NEMOs and regulatory authorities.

(31) In line with Article 8 of Regulation (EC) No 713/2009 of the European Parliament and of the Council ([1]), the Agency should take a decision if the competent national regulatory authorities are not able to reach an agreement on common terms and conditions or methodologies.

(32) This Regulation has been developed in close cooperation with ACER, the ENTSO for Electricity and stakeholders, in order to adopt effective, balanced and proportionate rules in a transparent and participative manner. In accordance with Article 18(3) of Regulation (EC) No 714/2009, the Commission will consult ACER, the ENTSO for Electricity and other relevant stakeholders, notably NEMOs, before proposing any amendment to this regulation.

(33) This Regulation supplements Annex I of Regulation (EC) No 714/2009, in accordance with the principles set out in Article 16 of that Regulation.

(34) Due to the significant challenges in introducing single day-ahead and intraday coupling into the current market of Ireland and Northern Ireland, it is undergoing a process of major redesign. Additional time is, therefore, needed for the implementation of parts of this Regulation, with a number of transitional arrangements being put in place.

(35) The measures provided for in this Regulation are in accordance with the opinion of the Committee referred to in Article 23(1) of Regulation (EC) No 714/2009.

HAS ADOPTED THIS REGULATION:

TITLE I

GENERAL PROVISIONS

Article 1

Subject matter and scope

1. This Regulation lays down detailed guidelines on cross-zonal capacity allocation and congestion management in the day-ahead and intraday markets, including the requirements for the establishment of common methodologies for determining the volumes of capacity simultaneously available between bidding zones, criteria to assess efficiency and a review process for defining bidding zones.

([1]) Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators (OJ L 211, 14.8.2009, p. 1).

2. This Regulation shall apply to all transmission systems and interconnections in the Union except the transmission systems on islands which are not connected with other transmission systems via interconnections.

3. In Member States where more than one transmission system operator exists, this Regulation shall apply to all transmission system operators within that Member State. Where a transmission system operator does not have a function relevant to one or more obligations under this Regulation, Member States may provide that the responsibility for complying with those obligations is assigned to one or more different, specific transmission system operators.

4. The Union single day-ahead and intraday coupling may be opened to market operators and TSOs operating in Switzerland on the condition that the national law in that country implements the main provisions of Union electricity market legislation and that there is an intergovernmental agreement on electricity cooperation between the Union and Switzerland.

5. Subject to the conditions in paragraph 4 above being fulfilled, participation by Switzerland in day-ahead coupling and single intraday coupling shall be decided by the Commission based on an opinion given by the Agency. The rights and responsibilities of Swiss NEMOs and TSOs joining single day-ahead coupling shall be consistent with the rights and responsibilities of NEMOs and TSOs operating in the Union to allow a smooth functioning of the single day-ahead and intraday coupling systems implemented at Union level and a level-playing field for all stakeholders.

Article 2

Definitions

For the purposes of this Regulation, the definitions in Article 2 of Regulation (EC) No 714/2009, Article 2 of Commission Regulation (EU) No 543/2013 ([1]) and Article 2 of Directive 2009/72/EC of the European Parliament and of the Council ([2]) shall apply.

In addition, the following definitions shall apply:

1. 'individual grid model' means a data set describing power system characteristics (generation, load and grid topology) and related rules to change these characteristics during capacity calculation, prepared by the responsible TSOs, to be merged with other individual grid model components in order to create the common grid model;

2. 'common grid model' means a Union-wide data set agreed between various TSOs describing the main characteristic of the power system (generation, loads and grid topology) and rules for changing these characteristics during the capacity calculation process;

3. 'capacity calculation region' means the geographic area in which coordinated capacity calculation is applied;

4. 'scenario' means the forecasted status of the power system for a given time-frame;

5. 'net position' means the netted sum of electricity exports and imports for each market time unit for a bidding zone;

6. 'allocation constraints' means the constraints to be respected during capacity allocation to maintain the transmission system within operational security limits and have not been translated into cross-zonal capacity or that are needed to increase the efficiency of capacity allocation;

7. 'operational security limits' means the acceptable operating boundaries for secure grid operation such as thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits;

8. 'coordinated net transmission capacity approach' means the capacity calculation method based on the principle of assessing and defining *ex ante* a maximum energy exchange between adjacent bidding zones;

([1]) Commission Regulation (EU) No 543/2013 of 14 June 2013 on submission and publication of data in electricity markets and amending Annex I to Regulation (EC) No 714/2009 of the European Parliament and of the Council (OJ L 163, 15.6.2013, p. 1).

([2]) Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC (OJ L 211, 14.8.2009, p. 55).

9. ‘flow-based approach’ means a capacity calculation method in which energy exchanges between bidding zones are limited by power transfer distribution factors and available margins on critical network elements;

10. ‘contingency’ means the identified and possible or already occurred fault of an element, including not only the transmission system elements, but also significant grid users and distribution network elements if relevant for the transmission system operational security;

11. ‘coordinated capacity calculator’ means the entity or entities with the task of calculating transmission capacity, at regional level or above;

12. ‘generation shift key’ means a method of translating a net position change of a given bidding zone into estimated specific injection increases or decreases in the common grid model;

13. ‘remedial action’ means any measure applied by a TSO or several TSOs, manually or automatically, in order to maintain operational security;

14. ‘reliability margin’ means the reduction of cross-zonal capacity to cover the uncertainties within capacity calculation;

15. ‘market time’ means central European summer time or central European time, whichever is in effect;

16. ‘congestion income’ means the revenues received as a result of capacity allocation;

17. ‘market congestion’ means a situation in which the economic surplus for single day-ahead or intraday coupling has been limited by cross-zonal capacity or allocation constraints;

18. ‘physical congestion’ means any network situation where forecasted or realised power flows violate the thermal limits of the elements of the grid and voltage stability or the angle stability limits of the power system;

19. ‘structural congestion’ means congestion in the transmission system that can be unambiguously defined, is predictable, is geographically stable over time and is frequently reoccurring under normal power system conditions;

20. ‘matching’ means the trading mode through which sell orders are assigned to appropriate buy orders to ensure the maximisation of economic surplus for single day-ahead or intraday coupling;

21. ‘order’ means an intention to purchase or sell energy or capacity expressed by a market participant subject to specified execution conditions;

22. ‘matched orders’ means all buy and sell orders matched by the price coupling algorithm or the continuous trade matching algorithm;

23. ‘nominated electricity market operator (NEMO)’ means an entity designated by the competent authority to perform tasks related to single day-ahead or single intraday coupling;

24. ‘shared order book’ means a module in the continuous intraday coupling system collecting all matchable orders from the NEMOs participating in single intraday coupling and performing continuous matching of those orders;

25. ‘trade’ means one or more matched orders;

26. ‘single day-ahead coupling’ means the auctioning process where collected orders are matched and cross-zonal capacity is allocated simultaneously for different bidding zones in the day-ahead market;

27. ‘single intraday coupling’ means the continuous process where collected orders are matched and cross-zonal capacity is allocated simultaneously for different bidding zones in the intraday market;

28. ‘price coupling algorithm’ means the algorithm used in single day-ahead coupling for simultaneously matching orders and allocating cross-zonal capacities;

29. ‘continuous trading matching algorithm’ means the algorithm used in single intraday coupling for matching orders and allocating cross-zonal capacities continuously;

30. ‘market coupling operator (MCO) function’ means the task of matching orders from the day-ahead and intraday markets for different bidding zones and simultaneously allocating cross-zonal capacities;

31. ‘clearing price’ means the price determined by matching the highest accepted selling order and the lowest accepted buying order in the electricity market;

32. ‘scheduled exchange’ means an electricity transfer scheduled between geographic areas, for each market time unit and for a given direction;

33. ‘scheduled exchange calculator’ means the entity or entities with the task of calculating scheduled exchanges;

34. ‘day-ahead market time-frame’ means the time-frame of the electricity market until the day-ahead market gate closure time, where, for each market time unit, products are traded the day prior to delivery;

35. ‘day-ahead firmness deadline’ means the point in time after which cross-zonal capacity becomes firm;

36. ‘day-ahead market gate closure time’ means the point in time until which orders are accepted in the day-ahead market;

37. ‘intraday market time-frame’ means the time-frame of the electricity market after intraday cross-zonal gate opening time and before intraday cross-zonal gate closure time, where for each market time unit, products are traded prior to the delivery of the traded products;

38. ‘intraday cross-zonal gate opening time’ means the point in time when cross-zonal capacity between bidding zones is released for a given market time unit and a given bidding zone border;

39. ‘intraday cross-zonal gate closure time’ means the point in time where cross-zonal capacity allocation is no longer permitted for a given market time unit;

40. ‘capacity management module’ means a system containing up-to-date information on available cross-zonal capacity for the purpose of allocating intra-day cross-zonal capacity;

41. ‘non-standard intraday product’ means a product for continuous intraday coupling not for constant energy delivery or for a period exceeding one market time unit with specific characteristics designed to reflect system operation practices or market needs, for example orders covering multiple market time units or products reflecting production unit start-up costs;

42. ‘central counter party’ means the entity or entities with the task of entering into contracts with market participants, by novation of the contracts resulting from the matching process, and of organising the transfer of net positions resulting from capacity allocation with other central counter parties or shipping agents;

43. ‘shipping agent’ means the entity or entities with the task of transferring net positions between different central counter parties;

44. ‘firmness’ means a guarantee that cross-zonal capacity rights will remain unchanged and that a compensation is paid if they are nevertheless changed;

45. ‘*force majeure*’ means any unforeseeable or unusual event or situation beyond the reasonable control of a TSO, and not due to a fault of the TSO, which cannot be avoided or overcome with reasonable foresight and diligence, which cannot be solved by measures which are from a technical, financial or economic point of view reasonably possible for the TSO, which has actually happened and is objectively verifiable, and which makes it impossible for the TSO to fulfil, temporarily or permanently, its obligations in accordance with this Regulation;

46. ‘economic surplus for the single day-ahead or intraday coupling’ means the sum of (i) the supplier surplus for the single day-ahead or intraday coupling for the relevant time period, (ii) the consumer surplus for the single day-ahead or intraday coupling, (iii) the congestion income and (iv) other related costs and benefits where these increase economic efficiency for the relevant time period, supplier and consumer surplus being the difference between the accepted orders and the clearing price per energy unit multiplied by the volume of energy of the orders.

Article 3

Objectives of capacity allocation and congestion management cooperation

This Regulation aims at:

(a) promoting effective competition in the generation, trading and supply of electricity;

(b) ensuring optimal use of the transmission infrastructure;

(c) ensuring operational security;

(d) optimising the calculation and allocation of cross-zonal capacity;

(e) ensuring fair and non-discriminatory treatment of TSOs, NEMOs, the Agency, regulatory authorities and market participants;

(f) ensuring and enhancing the transparency and reliability of information;

(g) contributing to the efficient long-term operation and development of the electricity transmission system and electricity sector in the Union;

(h) respecting the need for a fair and orderly market and fair and orderly price formation;

(i) creating a level playing field for NEMOs;

(j) providing non-discriminatory access to cross-zonal capacity.

Article 4

NEMOs designation and revocation of the designation

1. Each Member State electrically connected to a bidding zone in another Member State shall ensure that one or more NEMOs are designated by four months after the entry into force of this Regulation to perform the single day-ahead and/or intraday coupling. For that purpose, domestic and non-domestic market operators may be invited to apply to be designated as a NEMO.

2. Each Member State concerned shall ensure that at least one NEMO is designated in each bidding zone on its territory. NEMOs shall be designated for an initial term of four years. Except where Article 5(1) applies, Member States shall allow applications for designation at least annually.

3. Unless otherwise provided by Member States, regulatory authorities shall be the designating authority, responsible for NEMO designation, monitoring of compliance with the designation criteria and, in the case of national legal monopolies, the approval of NEMO fees or the methodology to calculate NEMO fees. Member States may provide that authorities other than the regulatory authorities be the designating authority. In these circumstances Member States shall ensure that the designating authority has the same rights and obligations as the regulatory authorities in order to effectively carry out its tasks.

4. The designating authority shall assess whether NEMO candidates meet the criteria set out in Article 6. Those criteria shall apply regardless of whether one or more NEMOs are appointed. When deciding upon NEMO designations, any discrimination between applicants, notably between non-domestic and domestic applicants, shall be avoided. If the designating authority is not the regulatory authority, the regulatory authority shall give an opinion on the extent to which the applicant for designation meets the designation criteria laid down in Article 6. NEMO designations shall only be refused where the designation criteria in Article 6 are not met or in accordance with Article 5(1).

5. A NEMO designated in one Member State shall have the right to offer day-ahead and intraday trading services with delivery in another Member State. The trading rules in the latter Member State shall apply without the need for designation as a NEMO in that Member State. The designating authorities shall monitor all NEMOs performing single

day-ahead and/or intra-day coupling within their Member State. In accordance with Article 19 of Regulation (EC) No 714/2009 the designating authorities shall ensure compliance with this Regulation by all NEMOs performing single day-ahead and/or intra-day coupling within their Member State, regardless of where the NEMOs were designated. The authorities in charge of NEMO designation, monitoring and enforcement shall exchange all information necessary for an efficient supervision of NEMO activities.

A designated NEMO must notify the designating authority of another Member State if it proposes to perform single day-ahead or intraday coupling in that Member State two months before commencing operation.

6. By way of exception to paragraph 5 of this Article, a Member State may refuse the trading services by a NEMO designated in another Member State if:

(a) a national legal monopoly for day-ahead and intraday trading services exists in the Member State or bidding zone of the Member State where delivery takes place in accordance with Article 5(1); or

(b) the Member State where delivery takes place can establish that there are technical obstacles to delivery into that Member State of electricity purchased on day-ahead and intraday markets using NEMOs designated in another Member State linked to the need to ensure the objectives of this Regulation are met while maintaining operational security; or

(c) the trading rules in the Member State of delivery are not compatible with the delivery into that Member State of electricity purchased on the basis of day-ahead and intraday trading services provided by a NEMO designated in another Member State; or

(d) the NEMO is a national legal monopoly in accordance with Article 5 in the Member State where it is designated.

7. In case of a decision to refuse day-ahead and/or intraday trading services with delivery in another Member State, the Member State of delivery shall notify its decision to the NEMO and to the designating authority of the Member State where the NEMO is designated, as well as to the Agency and the Commission. The refusal shall be duly justified. In the cases set out in subparagraphs 6(b) and 6(c), the decision to refuse trading services with delivery in another Member State shall also set out how and by when the technical obstacles to trading can be overcome or the domestic trading rules can be made compatible with trading services with delivery in another Member State. The designating authority of the Member State refusing the trading services shall investigate the decision and publish an opinion on how to remove the obstacles to the trading services or how to make the trading services and the trading rules compatible.

8. The Member State where the NEMO has been designated shall ensure that designation is revoked if the NEMO fails to maintain compliance with the criteria in Article 6 and is not able to restore compliance within six months of being notified of such failure by the designating authority. If the regulatory authority is not responsible for designation and monitoring, they shall be consulted on the revocation. The designating authority shall also notify the designating authority of the other Member States in which that NEMO is active of its failure to maintain compliance at the same time it notifies the NEMO.

9. If a designating authority of a Member State finds that a NEMO active but not designated in its country fails to maintain compliance with the criteria in Article 6 with respect to its activities in this country, it must notify the NEMO of its non-compliance. If the NEMO does not restore compliance within three months of being notified, the designating authority can suspend the right to offer intraday and day-ahead trading services in this Member State until such time as the NEMO restores compliance. The designating authority shall notify the designating authority of the Member State in which the NEMO is designated, the Agency and the Commission.

10. The designating authority shall inform the Agency of the designation and revocation of NEMOs. The Agency shall maintain a list of designated NEMOs, their status and where they operate on its website.

Article 5

NEMOs designation in case of a national legal monopoly for trading services

1. If a national legal monopoly for day-ahead and intraday trading services which excludes the designation of more than one NEMO already exists in a Member State or Member State's bidding zone at the time of the entry into force of this Regulation, the Member State concerned must notify the Commission within two months after entry into force of this regulation and may refuse the designation of more than one NEMO per bidding zone.

If there are several applicants to be designated as the only NEMO, the Member State concerned shall designate the applicant which best meets the criteria listed in Article 6. If a Member State refuses the designation of more than one NEMO per bidding zone, the competent national authority shall fix or approve the NEMO fees for trading in the day-ahead and intraday markets, sufficiently in advance of their entry into force, or specify the methodologies used to calculate them.

In accordance with Article 4(6), the Member State concerned may also refuse cross-border trading services offered by a NEMO designated in another Member State; however, the protection of existing power exchanges in that Member State from economic disadvantages through competition is not a valid reason for refusal.

2. For the purposes of this regulation, a national legal monopoly is deemed to exist where national law expressly provides that no more than one entity within a Member State or Member State bidding zone can carry out day-ahead and intraday trading services.

3. Two years after the entry into force of this Regulation, the Commission shall forward a report to the European Parliament and the Council in accordance with Article 24 of Regulation (EC) No 714/2009 on the development of single day-ahead and intraday coupling in the Member States, with particular emphasis on the development of competition between NEMOs. On the basis of that report, and if the Commission deems that there is no justification for the continuation of national legal monopolies or for the continued refusal of a Member State to allow cross-border trading by a NEMO designated in another Member State, the Commission may consider appropriate legislative or other appropriate measures to further increase competition and trade between and within Member States. The Commission shall also include an assessment in the report evaluating the governance of single day-ahead and intraday coupling established by this Regulation, with particular emphasis on the transparency of MCO functions carried jointly by the NEMOs. On the basis of that report, and if the Commission deems that there is ambiguity in carrying out the monopolistic MCO functions and other NEMO tasks, the Commission may consider appropriate legislative or other appropriate measures to further increase transparency and efficient functioning of single day-ahead and intraday coupling.

Article 6

NEMO designation criteria

1. An applicant shall only be designated as a NEMO if it complies with all of the following requirements:

(a) it has contracted or contracts adequate resources for common, coordinated and compliant operation of single day-ahead and/or intraday coupling, including the resources necessary to fulfil the NEMO functions, financial resources, the necessary information technology, technical infrastructure and operational procedures or it shall provide proof that it is able to make these resources available within a reasonable preparatory period before taking up its tasks in accordance with Article 7;

(b) it shall be able to ensure that market participants have open access to information regarding the NEMO tasks in accordance with Article 7;

(c) it shall be cost-efficient with respect to single day-ahead and intraday coupling and shall in its internal accounting keep separate accounts for MCO functions and other activities in order to prevent cross-subsidisation;

(d) it shall have an adequate level of business separation from other market participants;

(e) if designated as a national legal monopoly for day-ahead and intraday trading services in a Member State, it shall not use the fees in Article 5(1) to finance its day-ahead or intraday activities in a Member State other than the one where these fees are collected;

(f) it shall be able to treat all market participants in a non-discriminatory way;

(g) it shall have appropriate market surveillance arrangements in place;

(h) it shall have in place appropriate transparency and confidentiality agreements with market participants and the TSOs;

(i) it shall be able to provide the necessary clearing and settlement services;

(j) it shall be able to put in place the necessary communication systems and routines for coordinating with the TSOs of the Member State.

2. The designation criteria set out in paragraph 1 shall be applied in such a way that competition between NEMOs is organised in a fair and non-discriminatory manner.

Article 7

NEMO tasks

1. NEMOs shall act as market operators in national or regional markets to perform in cooperation with TSOs single day-ahead and intraday coupling. Their tasks shall include receiving orders from market participants, having overall responsibility for matching and allocating orders in accordance with the single day-ahead and intraday coupling results, publishing prices and settling and clearing the contracts resulting from the trades according to relevant participant agreements and regulations.

With regard to single day-ahead and intraday coupling, NEMOs shall in particular be responsible for the following tasks:

(a) implementing the MCO functions set out in paragraph 2 in coordination with other NEMOs;

(b) establishing collectively the requirements for the single day-ahead and intraday coupling, requirements for MCO functions and the price coupling algorithm with respect to all matters related to electricity market functioning in accordance with paragraph 2 of this Article, and Articles 36 and 37;

(c) determining maximum and minimum prices in accordance with Articles 41 and 54;

(d) making anonymous and sharing the received order information necessary to perform the MCO functions provided for in paragraph 2 of this Article and Articles 40 and 53;

(e) assessing the results calculated by the MCO functions set out in paragraph 2 of this Article allocating the orders based on these results, validating the results as final if they are considered correct and taking responsibility for them in accordance with Articles 48 and 60;

(f) informing the market participants on the results of their orders in accordance with Articles 48 and 60;

(g) acting as central counter parties for clearing and settlement of the exchange of energy resulting from single day-ahead and intraday coupling in accordance with Article 68(3);

(h) establishing jointly with relevant NEMOs and TSOs back-up procedures for national or regional market operation in accordance with Article 36(3) if no results are available from the MCO functions in accordance with Article 39(2), taking account of fallback procedures provided for in Article 44;

(i) jointly providing single day-ahead and intraday coupling cost forecasts and cost information to competent regulatory authorities and TSOs where NEMO costs for establishing, amending and operating single day-ahead and intraday coupling are to be covered by the concerned TSOs' contribution in accordance with Articles 75 to 77 and Article 80;

(j) Where applicable, in accordance with Article 45 and 57, coordinate with TSOs to establish arrangements concerning more than one NEMO within a bidding zone and perform single day-ahead and/or intraday coupling in line with the approved arrangements.

2. NEMOs shall carry out MCO functions jointly with other NEMOs. Those functions shall include the following:

(a) developing and maintaining the algorithms, systems and procedures for single day-ahead and intraday coupling in accordance with Articles 36 and 51;

(b) processing input data on cross-zonal capacity and allocation constraints provided by coordinated capacity calculators in accordance with Articles 46 and 58;

(c) operating the price coupling and continuous trading matching algorithms in accordance with Articles 48 and 60;

(d) validating and sending single day-ahead and intraday coupling results to the NEMOs in accordance with Articles 48 and 60.

3. By eight months after the entry into force of this Regulation all NEMOs shall submit to all regulatory authorities and the Agency a plan that sets out how to jointly set up and perform the MCO functions set out in paragraph 2, including necessary draft agreements between NEMOs and with third parties. The plan shall include a detailed description and the proposed timescale for implementation, which shall not be longer than 12 months, and a description of the expected impact of the terms and conditions or methodologies on the establishment and performance of the MCO functions in paragraph 2.

4. Cooperation between NEMOs shall be strictly limited to what is necessary for the efficient and secure design, implementation and operation of single day-ahead and intraday coupling. The joint performance of MCO functions shall be based on the principle of non-discrimination and ensure that no NEMO can benefit from unjustified economic advantages through participation in MCO functions.

5. The Agency shall monitor NEMOs' progress in establishing and performing the MCO functions, in particular regarding the contractual and regulatory framework and regarding technical preparedness to fulfil the MCO functions. By 12 months after entry into force of this Regulation, the Agency shall report to the Commission whether progress in establishing and performing single day-ahead or intraday coupling is satisfactory.

The Agency may assess the effectiveness and efficiency of establishment and performance of the MCO function at any time. If that assessment demonstrates that the requirements are not fulfilled, the Agency may recommend to the Commission any further measures needed for timely effective and efficient delivery of single day-ahead and intraday coupling.

6. If NEMOs fail to submit a plan in accordance with Article 7(3) to establish the MCO functions referred to in paragraph 2 of this Article for either the intraday or the day-ahead market time-frames, the Commission may, in accordance with Article 9(4), propose an amendment to this Regulation, considering in particular appointing the ENTSO for Electricity or another entity to carry the MCO functions for single day-ahead coupling or for intraday coupling instead of the NEMOs.

Article 8

TSOs' tasks related to single day-ahead and intraday coupling

1. In Member States electrically connected to another Member State all TSOs shall participate in the single day-ahead and intraday coupling.

2. TSOs shall:

(a) jointly establish TSO requirements for the price coupling and continuous trading matching algorithms for all aspects related to capacity allocation in accordance with Article 37(1)(a);

(b) jointly validate the matching algorithms against the requirements referred to in point (a) of this paragraph in accordance with Article 37(4);

(c) establish and perform capacity calculation in accordance with Articles 14 to 30;

(d) where necessary, establish cross zonal capacity allocation and other arrangements in accordance with Articles 45 and 57;

(e) calculate and send cross zonal capacities and allocation constraints in accordance with Articles 46 and 58;

(f) verify single day-ahead coupling results in terms of validated cross-zonal capacities and allocation constraints in accordance with Articles 48(2) and 52;

(g) where required, establish scheduled exchange calculators for calculating and publishing scheduled exchanges on borders between bidding zones in accordance with Articles 49 and 56;

(h) respect the results from single day-ahead and intraday coupling calculated in accordance with Article 39 and Article 52;

(i) establish and operate fallback procedures as appropriate for capacity allocation in accordance with Article 44;

(j) propose the intraday cross-zonal gate opening and intraday cross-zonal gate closure times in accordance with Article 59;

(k) share congestion income in accordance with the methodology jointly developed in accordance with Article 73;

(l) where so agreed, act as shipping agents transferring net positions in accordance with Article 68(6).

Article 9

Adoption of terms and conditions or methodologies

1. TSOs and NEMOs shall develop the terms and conditions or methodologies required by this Regulation and submit them for approval to the competent regulatory authorities within the respective deadlines set out in this Regulation. Where a proposal for terms and conditions or methodologies pursuant to this Regulation needs to be developed and agreed by more than one TSO or NEMO, the participating TSOs and NEMOs shall closely cooperate. TSOs, with the assistance of ENTSO for Electricity, and all NEMOs shall regularly inform the competent regulatory authorities and the Agency about the progress of developing these terms and conditions or methodologies.

2. TSOs or NEMOs deciding on proposals for terms and conditions or methodologies in accordance with Article 9(6) shall decide with qualified majority if no consensus could be reached among them. The qualified majority shall be reached within each of the respective voting classes of TSOs and NEMOs. A qualified majority for proposals in accordance with Article 9(6) shall require a majority of:

(a) TSOs or NEMOs representing at least 55 % of the Member States; and

(b) TSOs or NEMOs representing Member States comprising at least 65 % of the population of the Union.

A blocking minority for decisions in accordance with Article 9(6) must include TSOs or NEMOs representing at least four Member States, failing of which the qualified majority shall be deemed attained.

For TSO decisions under Article 9(6), one vote shall be attributed per Member State. If there is more than one TSO in the territory of a Member State, the Member State shall allocate the voting powers among the TSOs.

For NEMO decisions in accordance with Article 9(6), one vote shall be attributed per Member State. Each NEMO shall have a number of votes equal to the number of Member States where it is designated. If more than one NEMO is designated in the territory of a Member State, the Member State shall allocate the voting powers among the NEMOs, taking into account their respective volume of transacted electricity in that particular Member State in the preceding financial year.

3. Except for Articles 43(1), 44, 56(1), 63 and 74(1) TSOs deciding on proposals for terms and conditions or methodologies in accordance with Article 9(7) shall decide with qualified majority if no consensus can be reached among them and where the regions concerned are composed of more than five Member States. The qualified majority shall be reached within each of the respective voting classes of TSOs and NEMOs. A qualified majority for proposals in accordance with Article 9(7), shall require a majority of:

(a) TSOs representing at least 72 % of the Member States concerned; and

(b) TSOs representing Member States comprising at least 65 % of the population of the concerned region.

A blocking minority for decisions in accordance with Article 9(7) must include at least the minimum number of TSOs representing more than 35 % of the population of the participating Member States, plus TSOs representing at least one additional Member State concerned, failing of which the qualified majority shall be deemed attained.

TSOs deciding on proposals for terms and conditions or methodologies in accordance with Article 9(7) in relation to regions composed of five Member States or less shall decide based on consensus.

For TSO decisions under Article 9(7), one vote shall be attributed per Member State. If there is more than one TSO in the territory of a Member State, the Member State shall allocate the voting powers among the TSOs.

NEMOs deciding on proposals for terms and conditions or methodologies in accordance with Article 9(7) shall decide based on consensus.

4. If TSOs or NEMOs fail to submit a proposal for terms and conditions or methodologies to the national regulatory authorities within the deadlines defined in this Regulation, they shall provide the competent regulatory authorities and the Agency with the relevant drafts of the terms and conditions or methodologies, and explain what has prevented an agreement. The Agency shall inform the Commission and shall, in cooperation with the competent regulatory authorities, at the Commission's request, investigate the reasons for the failure and inform the Commission thereof. The Commission shall take the appropriate steps to make possible the adoption of the required terms and conditions or methodologies within four months from the receipt of the Agency's information.

5. Each regulatory authority shall approve the terms and conditions or methodologies used to calculate or set out the single day-ahead and intraday coupling developed by TSOs and NEMOs. They shall be responsible for approving the terms and conditions or methodologies referred to in paragraphs 6, 7 and 8.

6. The proposals for the following terms and conditions or methodologies shall be subject to approval by all regulatory authorities:

(a) the plan on joint performance of MCO functions in accordance with Article 7(3);

(b) the capacity calculation regions in accordance with Article 15(1);

(c) the generation and load data provision methodology in accordance with Article 16(1);

(d) the common grid model methodology in accordance with Article 17(1);

(e) the proposal for a harmonised capacity calculation methodology in accordance with Article 21(4);

(f) back-up methodology in accordance with Article 36(3);

(g) the algorithm submitted by NEMOs in accordance with Article 37(5), including the TSOs' and NEMOs' sets of requirements for algorithm development in accordance with Article 37(1);

(h) products that can be taken into account by NEMOs in the single day-ahead and intraday coupling process in accordance with Articles 40 and 53;

(i) the maximum and minimum prices in accordance with Articles 41(1) and 54(2);

(j) the intraday capacity pricing methodology to be developed in accordance with Article 55(1);

(k) the intraday cross–zonal gate opening and intraday cross-zonal gate closure times in accordance with Article 59(1);

(l) the day-ahead firmness deadline in accordance with Article 69;

(m) the congestion income distribution methodology in accordance with Article 73(1);

7. The proposals for the following terms and conditions or methodologies shall be subject to approval by all regulatory authorities of the concerned region:

(a) the common capacity calculation methodology in accordance with Article 20(2);

(b) decisions on the introduction and postponement of flow-based calculation in accordance with Article 20(2) to (6) and on exemptions in accordance with Article 20(7);

(c) the methodology for coordinated redispatching and countertrading in accordance with Article 35(1);

(d) the common methodologies for the calculation of scheduled exchanges in accordance with Articles 43(1) and 56(1);

(e) the fallback procedures in accordance with Article 44;

(f) complementary regional auctions in accordance with Article 63(1);

(g) the conditions for the provision of explicit allocation in accordance with Article 64(2);

(h) the redispatching or countertrading cost sharing methodology in accordance with Article 74(1).

8. The following terms and conditions or methodologies shall be subject to individual approval by each regulatory authority or other competent authority of the Member States concerned:

(a) where applicable, NEMO designation and revocation or suspension of designation in accordance with Article 4(2), 4(8) and 4(9);

(b) if applicable, the fees or the methodologies used to calculate the fees of NEMOs relating to trading in the day-ahead and intraday markets in accordance with Article 5(1);

(c) proposals of individual TSOs for a review of the bidding zone configuration in accordance with Article 32(1)(d);

(d) where applicable, the proposal for cross-zonal capacity allocation and other arrangements in accordance with Articles 45 and 57;

(e) capacity allocation and congestion management costs in accordance with Articles 75 to 79;

(f) if applicable, cost sharing of regional costs of single day-ahead and intraday coupling in accordance with Article 80(4).

9. The proposal for terms and conditions or methodologies shall include a proposed timescale for their implementation and a description of their expected impact on the objectives of this Regulation. Proposals on terms and conditions or methodologies subject to the approval by several or all regulatory authorities shall be submitted to the Agency at the same time that they are submitted to regulatory authorities. Upon request by the competent regulatory authorities, the Agency shall issue an opinion within three months on the proposals for terms and conditions or methodologies.

10. Where the approval of the terms and conditions or methodologies requires a decision by more than one regulatory authority, the competent regulatory authorities shall consult and closely cooperate and coordinate with each other in order reach an agreement. Where applicable, the competent regulatory authorities shall take into account the opinion of the Agency. Regulatory authorities shall take decisions concerning the submitted terms and conditions or methodologies in accordance with paragraphs 6, 7 and 8, within six months following the receipt of the terms and conditions or methodologies by the regulatory authority or, where applicable, by the last regulatory authority concerned.

11. Where the regulatory authorities have not been able to reach agreement within the period referred to in paragraph 10, or upon their joint request, the Agency shall adopt a decision concerning the submitted proposals for terms and conditions or methodologies within six months, in accordance with Article 8(1) of Regulation (EC) No 713/2009.

12. In the event that one or several regulatory authorities request an amendment to approve the terms and conditions or methodologies submitted in accordance with paragraphs 6, 7 and 8, the relevant TSOs or NEMOs shall submit a proposal for amended terms and conditions or methodologies for approval within two months following the requirement from the regulatory authorities. The competent regulatory authorities shall decide on the amended terms and conditions or methodologies within two months following their submission. Where the competent regulatory authorities have not been able to reach an agreement on terms and conditions or methodologies pursuant to paragraphs (6) and (7) within the two-month deadline, or upon their joint request, the Agency shall adopt a decision concerning the amended terms and conditions or methodologies within six months, in accordance with Article 8(1) of Regulation (EC) No 713/2009. If the relevant TSOs or NEMOs fail to submit a proposal for amended terms and conditions or methodologies, the procedure provided for in paragraph 4 of this Article shall apply.

13. TSOs or NEMOs responsible for developing a proposal for terms and conditions or methodologies or regulatory authorities responsible for their adoption in accordance with paragraphs 6, 7 and 8, may request amendments of these terms and conditions or methodologies.

The proposals for amendment to the terms and conditions or methodologies shall be submitted to consultation in accordance with the procedure set out in Article 12 and approved in accordance with the procedure set out in this Article.

14. TSOs and NEMOs responsible for establishing the terms and conditions or methodologies in accordance with this Regulation shall publish them on the internet after approval by the competent regulatory authorities or, if no such approval is required, after their establishment, except where such information is considered as confidential in accordance with Article 13.

Article 10

Day-to-day management of the single day-ahead and intraday coupling

TSOs and NEMOs shall jointly organise the day-to-day management of the single day-ahead and intraday coupling. They shall meet regularly to discuss and decide on day-to-day operational issues. TSOs and NEMOs shall invite the Agency and the Commission as observers to these meetings and shall publish summary minutes of the meetings.

Article 11

Stakeholder involvement

The Agency, in close cooperation with ENTSO for Electricity, shall organise stakeholder involvement regarding single day-ahead and intraday coupling and other aspects of the implementation of this Regulation. This shall include regular meetings with stakeholders to identify problems and propose improvements notably related to the single day-ahead and intraday coupling. This shall not replace the stakeholder consultations in accordance with Article 12.

Article 12

Consultation

1. TSOs and NEMOs responsible for submitting proposals for terms and conditions or methodologies or their amendments in accordance with this Regulation shall consult stakeholders, including the relevant authorities of each Member State, on the draft proposals for terms and conditions or methodologies where explicitly set out in this Regulation. The consultation shall last for a period of not less than one month.

2. The proposals for terms and conditions or methodologies submitted by the TSOs and NEMOs at Union level shall be published and submitted to consultation at Union level. Proposals submitted by the TSOs and NEMOs at regional level shall be submitted to consultation at least at regional level. Parties submitting proposals at bilateral or at multilateral level shall consult at least the Member States concerned.

3. The entities responsible for the proposal for terms and conditions or methodologies shall duly consider the views of stakeholders resulting from the consultations undertaken in accordance with paragraph 1, prior to its submission for regulatory approval if required in accordance with Article 9 or prior to publication in all other cases. In all cases, a clear and robust justification for including or not the views resulting from the consultation shall be developed in the submission and published in a timely manner before or simultaneously with the publication of the proposal for terms and conditions or methodologies.

Article 13

Confidentiality obligations

1. Any confidential information received, exchanged or transmitted pursuant to this Regulation shall be subject to the conditions of professional secrecy laid down in paragraphs 2, 3 and 4.

2. The obligation of professional secrecy shall apply to any person subject to the provisions of this Regulation.

3. Confidential information received by the persons referred to in paragraph 2 in the course of their duties may not be divulged to any other person or authority, without prejudice to cases covered by national law, the other provisions of this Regulation or other relevant Union legislation.

4. Without prejudice to cases covered by national law, regulatory authorities, bodies or persons which receive confidential information pursuant to this Regulation may use it only for the purpose of the performance of their functions under this Regulation.

TITLE II

REQUIREMENTS FOR TERMS, CONDITIONS AND METHODOLOGIES CONCERNING CAPACITY ALLOCATION AND CONGESTION MANAGEMENT

CHAPTER 1

Capacity calculation

Section 1

General requirements

Article 14

Capacity calculation time-frames

1. All TSOs shall calculate cross-zonal capacity for at least the following time-frames:

(a) day-ahead, for the day-ahead market;

(b) intraday, for the intraday market.

2. For the day-ahead market time-frame, individual values for cross-zonal capacity for each day-ahead market time unit shall be calculated. For the intraday market time-frame, individual values for cross-zonal capacity for each remaining intraday market time unit shall be calculated.

3. For the day-ahead market time-frame, the capacity calculation shall be based on the latest available information. The information update for the day-ahead market time-frame shall not start before 15:00 market time two days before the day of delivery.

4. All TSOs in each capacity calculation region shall ensure that cross-zonal capacity is recalculated within the intraday market time-frame based on the latest available information. The frequency of this recalculation shall take into consideration efficiency and operational security.

Article 15

Capacity calculation regions

1. By three months after the entry into force of this Regulation all TSOs shall jointly develop a common proposal regarding the determination of capacity calculation regions. The proposal shall be subject to consultation in accordance with Article 12.

2. The proposal referred to in paragraph 1 shall define the bidding zone borders attributed to TSOs who are members of each capacity calculation region. The following requirements shall be met:

(a) it shall take into consideration the regions specified in point 3(2) of Annex I to Regulation (EC) No 714/2009;

(b) each bidding zone border, or two separate bidding zone borders if applicable, through which interconnection between two bidding zones exists, shall be assigned to one capacity calculation region;

(c) at least those TSOs shall be assigned to all capacity calculation regions in which they have bidding zone borders.

3. Capacity calculation regions applying a flow-based approach shall be merged into one capacity calculation region if the following cumulative conditions are fulfilled:

(a) their transmission systems are directly linked to each other;

(b) they participate in the same single day-ahead or intraday coupling area;

(c) merging them is more efficient than keeping them separate. The competent regulatory authorities may request a joint cost-benefit analysis from the TSOs concerned to assess the efficiency of the merger.

Section 2

The common grid model

Article 16

Generation and load data provision methodology

1. By 10 months after the entry into force of this Regulation all TSOs shall jointly develop a proposal for a single methodology for the delivery of the generation and load data required to establish the common grid model, which shall be subject to consultation in accordance with Article 12. The proposal shall include a justification based on the objectives of this Regulation for requiring the information.

2. The proposal for the generation and load data provision methodology shall specify which generation units and loads are required to provide information to their respective TSOs for the purposes of capacity calculation.

3. The proposal for a generation and load data provision methodology shall specify the information to be provided by generation units and loads to TSOs. The information shall at least include the following:

(a) information related to their technical characteristics;

(b) information related to the availability of generation units and loads;

(c) information related to the schedules of generation units;

(d) relevant available information relating to how generation units will be dispatched.

4. The methodology shall specify the deadlines applicable to generation units and loads for providing the information referred to in paragraph 3.

5. Each TSO shall use and share with other TSOs the information referred to in paragraph 3. The information referred to in paragraph 3(d) shall be used for capacity calculation purposes only.

6. No later than two months after the approval of the generation and load data provision methodology by all regulatory authorities, ENTSO for Electricity shall publish:

(a) a list of the entities required to provide information to the TSOs;

(b) a list of the information referred to in paragraph 3 to be provided;

(c) deadlines for providing information.

Article 17

Common grid model methodology

1. By 10 months after the entering into force of this Regulation all TSOs shall jointly develop a proposal for a common grid model methodology. The proposal shall be subject to consultation in accordance with Article 12.

2. The common grid model methodology shall enable a common grid model to be established. It shall contain at least the following items:

(a) a definition of scenarios in accordance with Article 18;

(b) a definition of individual grid models in accordance with Article 19;

(c) a description of the process for merging individual grid models to form the common grid model.

Article 18

Scenarios

1. All TSOs shall jointly develop common scenarios for each capacity calculation time-frame referred to in Article 14(1)(a) and (b). The common scenarios shall be used to describe a specific forecast situation for generation, load and grid topology for the transmission system in the common grid model.

2. One scenario per market time unit shall be developed both for the day-ahead and the intraday capacity calculation time-frames.

3. For each scenario, all TSOs shall jointly draw up common rules for determining the net position in each bidding zone and the flow for each direct current line. These common rules shall be based on the best forecast of the net position for each bidding zone and on the best forecast of the flows on each direct current line for each scenario and shall include the overall balance between load and generation for the transmission system in the Union. There shall be no undue discrimination between internal and cross-zonal exchanges when defining scenarios, in line with point 1.7 of Annex I to Regulation (EC) No 714/2009.

Article 19

Individual grid model

1. For each bidding zone and for each scenario:

(a) all TSOs in the bidding zone shall jointly provide a single individual grid model which complies with Article 18(3); or

(b) each TSO in the bidding zone shall provide an individual grid model for its control area, including interconnections, provided that the sum of net positions in the control areas, including interconnections, covering the bidding zone complies with Article 18(3).

2. Each individual grid model shall represent the best possible forecast of transmission system conditions for each scenario specified by the TSO(s) at the time when the individual grid model is created.

3. Individual grid models shall cover all network elements of the transmission system that are used in regional operational security analysis for the concerned time-frame.

4. All TSOs shall harmonise to the maximum possible extent the way in which individual grid models are built.

5. Each TSO shall provide all necessary data in the individual grid model to allow active and reactive power flow and voltage analyses in steady state.

6. Where appropriate, and upon agreement between all TSOs within a capacity calculation region, each TSO in that capacity calculation region shall exchange data between each other to enable voltage and dynamic stability analyses.

Section 3

Capacity calculation methodologies

Article 20

Introduction of flow-based capacity calculation methodology

1. For the day-ahead market time-frame and intraday market time-frame the approach used in the common capacity calculation methodologies shall be a flow-based approach, except where the requirement under paragraph 7 is met.

2. No later than 10 months after the approval of the proposal for a capacity calculation region in accordance with Article 15(1), all TSOs in each capacity calculation region shall submit a proposal for a common coordinated capacity calculation methodology within the respective region. The proposal shall be subject to consultation in accordance with Article 12. The proposal for the capacity calculation methodology within regions pursuant to this paragraph in capacity calculation regions based on the 'North-West Europe' ('NWE') and 'Central Eastern Europe' ('CEE') as defined in points (b), and (d) of point 3.2 of Annex I to Regulation (EC) No 714/2009 as well as in regions referred to in paragraph 3 and 4, shall be complemented with a common framework for coordination and compatibility of flow-based methodologies across regions to be developed in accordance with paragraph 5.

3. The TSOs from the capacity calculation region where Italy, as defined in point (c) of point 3.2 of Annex I to Regulation (EC) No 714/2009, is included, may extend the deadline without prejudice to the obligation in paragraph 1 for submitting the proposal for a common coordinated capacity calculation methodology using flow-based approach for the respective region pursuant to paragraph 2 up to six months after Switzerland joins the single day-ahead coupling. The proposal does not have to include bidding zone borders within Italy and between Italy and Greece.

4. No later than six months after at least all South East Europe Energy Community Contracting Parties participate in the single day-ahead coupling, the TSOs from at least Croatia, Romania, Bulgaria and Greece shall jointly submit a proposal to introduce a common capacity calculation methodology using the flow-based approach for the day-ahead and intraday market time-frame. The proposal shall provide for an implementation date of the common capacity calculation methodology using the flow-based approach of no longer than two years after the participation of all SEE Energy Community Contracting Parties in the single day-ahead coupling. The TSOs from Member States which have borders with other regions are encouraged to join the initiatives to implement a common flow-based capacity calculation methodology with these regions.

5. At the time when two or more adjacent capacity calculation regions in the same synchronous area implement a capacity calculation methodology using the flow-based approach for the day-ahead or the intraday market time-frame, they shall be considered as one region for this purpose and the TSOs from this region shall submit within six months a proposal for applying a common capacity calculation methodology using the flow-based approach for the day-ahead or intraday market time-frame. The proposal shall provide for an implementation date of the common cross regional capacity calculation methodology of no longer than 12 months after the implementation of the flow-based approach in these regions for the methodology for the day-ahead market time-frame, and 18 months for the methodology for the intraday time-frame. The timelines indicated in this paragraph may be adapted in accordance with paragraph 6.

The methodology in the two capacity calculation regions which have initiated developing a common capacity calculation methodology may be implemented first before developing a common capacity calculation methodology with any further capacity calculation region.

6. If the TSOs concerned are able to demonstrate that the application of common flow-based methodologies in accordance with paragraphs 4 and 5 would not yet be more efficient assuming the same level of operational security, they may jointly request the competent regulatory authorities to postpone the deadlines.

7. TSOs may jointly request the competent regulatory authorities to apply the coordinated net transmission capacity approach in regions and bidding zone borders other than those referred to in paragraphs 2 to 4, if the TSOs concerned are able to demonstrate that the application of the capacity calculation methodology using the flow-based approach would not yet be more efficient compared to the coordinated net transmission capacity approach and assuming the same level of operational security in the concerned region.

8. To enable market participants to adapt to any change in the capacity calculation approach, the TSOs concerned shall test the new approach alongside the existing approach and involve market participants for at least six months before implementing a proposal for changing their capacity calculation approach.

9. The TSOs of each capacity calculation region applying the flow-based approach shall establish and make available a tool which enables market participants to evaluate the interaction between cross-zonal capacities and cross-zonal exchanges between bidding zones.

Article 21

Capacity calculation methodology

1. The proposal for a common capacity calculation methodology for a capacity calculation region determined in accordance with Article 20(2) shall include at least the following items for each capacity calculation time-frame:

(a) methodologies for the calculation of the inputs to capacity calculation, which shall include the following parameters:

(i) a methodology for determining the reliability margin in accordance with Article 22;

(ii) the methodologies for determining operational security limits, contingencies relevant to capacity calculation and allocation constraints that may be applied in accordance with Article 23;

(iii) the methodology for determining the generation shift keys in accordance with Article 24;

(iv) the methodology for determining remedial actions to be considered in capacity calculation in accordance with Article 25.

(b) a detailed description of the capacity calculation approach which shall include the following:

(i) a mathematical description of the applied capacity calculation approach with different capacity calculation inputs;

(ii) rules for avoiding undue discrimination between internal and cross-zonal exchanges to ensure compliance with point 1.7 of Annex I to Regulation (EC) No 714/2009;

(iii) rules for taking into account, where appropriate, previously allocated cross-zonal capacity;

(iv) rules on the adjustment of power flows on critical network elements or of cross-zonal capacity due to remedial actions in accordance with Article 25;

(v) for the flow-based approach, a mathematical description of the calculation of power transfer distribution factors and of the calculation of available margins on critical network elements;

(vi) for the coordinated net transmission capacity approach, the rules for calculating cross-zonal capacity, including the rules for efficiently sharing the power flow capabilities of critical network elements among different bidding zone borders;

(vii) where the power flows on critical network elements are influenced by cross-zonal power exchanges in different capacity calculation regions, the rules for sharing the power flow capabilities of critical network elements among different capacity calculation regions in order to accommodate these flows.

(c) a methodology for the validation of cross-zonal capacity in accordance with Article 26.

2. For the intraday capacity calculation time-frame, the capacity calculation methodology shall also state the frequency at which capacity will be reassessed in accordance with Article 14(4), giving reasons for the chosen frequency.

3. The capacity calculation methodology shall include a fallback procedure for the case where the initial capacity calculation does not lead to any results.

4. All TSOs in each capacity calculation region shall, as far as possible, use harmonised capacity calculation inputs. By 31 December 2020, all regions shall use a harmonised capacity calculation methodology which shall in particular provide for a harmonised capacity calculation methodology for the flow-based and for the coordinated net transmission capacity approach. The harmonisation of capacity calculation methodology shall be subject to an efficiency assessment concerning the harmonisation of the flow-based methodologies and the coordinated net transmission capacity methodologies that provide for the same level of operational security. All TSOs shall submit the assessment with a proposal for the transition towards a harmonised capacity calculation methodology to all regulatory authorities within 12 months after at least two capacity calculation regions have implemented common capacity calculation methodology in accordance with Article 20(5).

Article 22

Reliability margin methodology

1. The proposal for a common capacity calculation methodology shall include a methodology to determine the reliability margin. The methodology to determine the reliability margin shall consist of two steps. First, the relevant TSOs shall estimate the probability distribution of deviations between the expected power flows at the time of the capacity calculation and realised power flows in real time. Second, the reliability margin shall be calculated by deriving a value from the probability distribution.

2. The methodology to determine the reliability margin shall set out the principles for calculating the probability distribution of the deviations between the expected power flows at the time of the capacity calculation and realised power flows in real time, and specify the uncertainties to be taken into account in the calculation. To determine those uncertainties, the methodology shall in particular take into account:

(a) unintended deviations of physical electricity flows within a market time unit caused by the adjustment of electricity flows within and between control areas, to maintain a constant frequency;

(b) uncertainties which could affect capacity calculation and which could occur between the capacity calculation time-frame and real time, for the market time unit being considered.

3. In the methodology to determine the reliability margin, TSOs shall also set out common harmonised principles for deriving the reliability margin from the probability distribution.

4. On the basis of the methodology adopted in accordance with paragraph 1, TSOs shall determine the reliability margin respecting the operational security limits and taking into account uncertainties between the capacity calculation time-frame and real time, and the remedial actions available after capacity calculation.

5. For each capacity calculation time-frame, the TSOs concerned shall determine the reliability margin for critical network elements, where the flow-based approach is applied, and for cross-zonal capacity, where the coordinated net transmission capacity approach is applied.

Article 23

Methodologies for operational security limits, contingencies and allocation constraints

1. Each TSO shall respect the operational security limits and contingencies used in operational security analysis.

2. If the operational security limits and contingencies used in capacity calculation are not the same as those used in operational security analysis, TSOs shall describe in the proposal for the common capacity calculation methodology the particular method and criteria they have used to determine the operational security limits and contingencies used for capacity calculation.

3. If TSOs apply allocation constraints, they can only be determined using:

(a) constraints that are needed to maintain the transmission system within operational security limits and that cannot be transformed efficiently into maximum flows on critical network elements; or

(b) constraints intended to increase the economic surplus for single day-ahead or intraday coupling.

Article 24

Generation shift keys methodology

1. The proposal for a common capacity calculation methodology shall include a proposal for a methodology to determine a common generation shift key for each bidding zone and scenario developed in accordance with Article 18.

2. The generation shift keys shall represent the best forecast of the relation of a change in the net position of a bidding zone to a specific change of generation or load in the common grid model. That forecast shall notably take into account the information from the generation and load data provision methodology.

Article 25

Methodology for remedial actions in capacity calculation

1. Each TSO within each capacity calculation region shall individually define the available remedial actions to be taken into account in capacity calculation to meet the objectives of this Regulation.

2. Each TSO within each capacity calculation region shall coordinate with the other TSOs in that region the use of remedial actions to be taken into account in capacity calculation and their actual application in real time operation.

3. To enable remedial actions to be taken into account in capacity calculation, all TSOs in each capacity calculation region shall agree on the use of remedial actions that require the action of more than one TSO.

4. Each TSO shall ensure that remedial actions are taken into account in capacity calculation under the condition that the available remedial actions remaining after calculation, taken together with the reliability margin referred to in Article 22, are sufficient to ensure operational security.

5. Each TSO shall take into account remedial actions without costs in capacity calculation.

6. Each TSO shall ensure that the remedial actions to be taken into account in capacity calculation are the same for all capacity calculation time-frames, taking into account their technical availabilities for each capacity calculation time-frame.

Article 26

Cross-zonal capacity validation methodology

1. Each TSO shall validate and have the right to correct cross-zonal capacity relevant to the TSO's bidding zone borders or critical network elements provided by the coordinated capacity calculators in accordance with Articles 27 to 31.

2. Where a coordinated net transmission capacity approach is applied, all TSOs in the capacity calculation region shall include in the capacity calculation methodology referred to in Article 21 a rule for splitting the correction of cross-zonal capacity between the different bidding zone borders.

3. Each TSO may reduce cross-zonal capacity during the validation of cross-zonal capacity referred to in paragraph 1 for reasons of operational security.

4. Each coordinated capacity calculator shall coordinate with the neighbouring coordinated capacity calculators during capacity calculation and validation.

5. Each coordinated capacity calculator shall, every three months, report all reductions made during the validation of cross-zonal capacity in accordance with paragraph 3 to all regulatory authorities of the capacity calculation region. This report shall include the location and amount of any reduction in cross-zonal capacity and shall give reasons for the reductions.

6. All the regulatory authorities of the capacity calculation region shall decide whether to publish all or part of the report referred to in paragraph 5.

Section 4

The capacity calculation process

Article 27

General provisions

1. No later than six months after the decision on the generation and load data provision methodology referred to in Article 16 and the common grid model methodology referred to in Article 17, all TSOs shall organise the process of merging the individual grid models.

2. No later than four months after the decisions on the capacity calculation methodologies referred to in Articles 20 and 21, all the TSOs in each capacity calculation region shall jointly set up the coordinated capacity calculators and establish rules governing their operations.

3. All TSOs of each capacity calculation region shall review the quality of data submitted within the capacity calculation every second year as part of the biennial report on capacity calculation and allocation produced in accordance with Article 31.

4. Using the latest available information, all TSOs shall regularly and at least once a year review and update:

(a) the operational security limits, contingencies and allocation constraints used for capacity calculation;

(b) the probability distribution of the deviations between expected power flows at the time of capacity calculation and realised power flows in real time used for calculation of reliability margins;

(c) the remedial actions taken into account in capacity calculation;

(d) the application of the methodologies for determining generation shift keys, critical network elements and contingencies referred to in Articles 22 to 24.

Article 28

Creation of a common grid model

1. For each capacity calculation time-frame referred to in Article 14(1), each generator or load unit subject to Article 16 shall provide the data specified in the generation and load data provision methodology to the TSO responsible for the respective control area within the specified deadlines.

2. Each generator or load unit providing information pursuant to Article 16(3) shall deliver the most reliable set of estimations practicable.

3. For each capacity calculation time-frame, each TSO shall establish the individual grid model for each scenario in accordance with Article 19, in order to merge individual grid models into a common grid model.

4. Each TSO shall deliver to the TSOs responsible for merging the individual grid models into a common grid model the most reliable set of estimations practicable for each individual grid model.

5. For each capacity calculation time-frame a single, Union-wide common grid model shall be created for each scenario as set out in Article 18 by merging inputs from all TSOs applying the capacity calculation process as set out in paragraph 3 of this Article.

Article 29

Regional calculation of cross-zonal capacity

1. For each capacity calculation time-frame, each TSO shall provide the coordinated capacity calculators and all other TSOs in the capacity calculation region with the following items: operational security limits, generation shift keys, remedial actions, reliability margins, allocation constraints and previously allocated cross-zonal capacity.

2. Each coordinated capacity calculator shall perform an operational security analysis applying operational security limits by using the common grid model created for each scenario in accordance with Article 28(5).

3. When calculating cross-zonal capacity, each coordinated capacity calculator shall:

(a) use generation shift keys to calculate the impact of changes in bidding zone net positions and of flows on direct current lines;

(b) ignore those critical network elements that are not significantly influenced by the changes in bidding zone net positions according to the methodology set out in Article 21; and,

(c) ensure that all sets of bidding zone net positions and flows on direct current lines not exceeding cross-zonal capacity comply with reliability margins and operational security limits in accordance with Article 21(1)(a)(i) and (ii), and take into account previously allocated cross-zonal capacity in accordance with Article 21(1)(b)(iii).

4. Each coordinated capacity calculator shall optimise cross-zonal capacity using available remedial actions taken into account in capacity calculation in accordance with Article 21(1)(a)(iv).

5. Each coordinated capacity calculator shall apply the sharing rules established in accordance with Article 21(1)(b)(vi).

6. Each coordinated capacity calculator shall respect the mathematical description of the applied capacity calculation approach established in accordance with Article 21(1)(b)(i).

7. Each coordinated capacity calculator applying the flow-based approach shall:

(a) use data on operational security limits to calculate the maximum flows on critical network elements;

(b) use the common grid model, generation shift keys and contingencies to calculate the power transfer distribution factors;

(c) use power transfer distribution factors to calculate the flows resulting from previously allocated cross-zonal capacity in the capacity calculation region;

(d) calculate flows on critical network elements for each scenario (taking into account contingencies), and adjust them by assuming no cross-zonal power exchanges within the capacity calculation region, applying the rules for avoiding undue discrimination between internal and cross-zonal power exchanges established in accordance with Article 21(1)(b)(ii);

(e) calculate the available margins on critical network elements, taking into account contingencies, which shall equal the maximum flows reduced by adjusted flows referred to in point (d), reliability margins, and flows resulting from previously allocated cross-zonal capacity;

(f) adjust the available margins on critical network elements or power transfer distribution factors using available remedial actions to be considered in capacity calculation in accordance with Article 25.

8. Each coordinated capacity calculator applying the coordinated net transmission capacity approach shall:

(a) use the common grid model, generation shift keys and contingencies to calculate maximum power exchange on bidding zone borders, which shall equal the maximum calculated exchange between two bidding zones on either side of the bidding zone border respecting operational security limits;

(b) adjust maximum power exchange using remedial actions taken into account in capacity calculation in accordance with Article 25;

(c) adjust maximum power exchange, applying rules for avoiding undue discrimination between internal and cross-zonal exchanges in accordance with Article 21(1)(b)(ii);

(d) apply the rules set out in accordance with Article 21(1)(b)(vi) for efficiently sharing the power flow capabilities of critical network elements among different bidding zone borders;

(e) calculate cross-zonal capacity, which shall be equal to maximum power exchange adjusted for the reliability margin and previously allocated cross-zonal capacity.

9. Each coordinated capacity calculator shall cooperate with the neighbouring coordinated capacity calculators. Neighbouring TSOs shall ensure such cooperation by exchanging and confirming information on interdependency with the relevant regional coordinated capacity calculators, for the purposes of capacity calculation and validation. Neighbouring TSOs shall provide information on interdependency to the coordinated capacity calculators before capacity calculation. An assessment of the accuracy of this information and corrective measures shall be included in the biennial report drafted in accordance with Article 31, where appropriate.

10. Each coordinated capacity calculator shall set:

(a) flow-based parameters for each bidding zone within the capacity calculation region, if applying the flow-based approach; or

(b) cross-zonal capacity values for each bidding zone border within the capacity calculation region, if applying the coordinated net transmission capacity approach.

11. Each coordinated capacity calculator shall submit the cross-zonal capacity to each TSO within its capacity calculation region for validation in accordance with Article 21(1)(c).

Article 30

Validation and delivery of cross-zonal capacity

1. Each TSO shall validate the results of the regional capacity calculation for its bidding zone borders or critical network elements, in accordance with Article 26.

2. Each TSO shall send its capacity validation and allocation constraints to the relevant coordinated capacity calculators and to the other TSOs of the relevant capacity calculation regions.

3. Each coordinated capacity calculator shall provide the validated cross-zonal capacities and allocation constraints for the purposes of allocating capacity in accordance with Articles 46 and 58.

Section 5

Biennial report on capacity calculation and allocation

Article 31

Biennial report on capacity calculation and allocation

1. By two years after the entry into force of this Regulation, ENTSO for Electricity shall draft a report on capacity calculation and allocation and submit it to the Agency.

2. If the Agency requests it, in every second subsequent year ENTSO for Electricity shall draft a report on capacity calculation and allocation and submit it to the Agency.

3. For each bidding zone, bidding zone border and capacity calculation region, the report on capacity calculation and allocation shall contain at least:

(a) the capacity calculation approach used;

(b) statistical indicators on reliability margins;

(c) statistical indicators of cross-zonal capacity, including allocation constraints where appropriate for each capacity calculation time-frame;

(d) quality indicators for the information used for the capacity calculation;

(e) where appropriate, proposed measures to improve capacity calculation;

(f) for regions where the coordinated net transmission capacity approach is applied, an analysis of whether the conditions specified in Article 20(7) are still fulfilled;

(g) indicators for assessing and following in the longer term the efficiency of single day-ahead and intraday coupling, including the merging of capacity calculation regions in accordance with Article 15(3) where relevant;

(h) recommendations for further development of single day-ahead and intraday coupling, including further harmonisation of methodologies, processes and governance arrangements.

4. After consulting the Agency, all TSOs shall jointly agree on the statistical and quality indicators for the report. The Agency may require the amendment of those indicators, prior to the agreement by the TSOs or during their application.

5. The Agency shall decide whether to publish all or part of the biennial report.

CHAPTER 2

Bidding zone configuration

Article 32

Reviewing existing bidding zone configurations

1. A review of an existing bidding zone configuration may be launched by:

(a) the Agency, in accordance with Article 34(7);

(b) several regulatory authorities, pursuant to a recommendation from the Agency in accordance with Article 34;

(c) TSOs of a capacity calculation region, together with all concerned TSOs whose control areas, including interconnectors, are within the geographic area in which the bidding zone configuration shall be assessed in accordance with paragraph 2(a);

(d) one single regulatory authority or TSO with the approval of its competent regulatory authority, for the bidding zones inside the TSO's control area, if the bidding zone configuration has negligible impact on neighbouring TSOs' control areas, including interconnectors, and the review of bidding zone configuration is necessary to improve efficiency, or to maintain operational security;

(e) Member States in a capacity calculation region.

2. If a review is launched in accordance with paragraph 1(a),(b), (c) or (e), the entity launching the review shall specify:

(a) the geographic area in which bidding zone configuration shall be assessed and the neighbouring geographic areas for which impacts shall be taken into account;

(b) the participating TSOs;

(c) the participating regulatory authorities.

3. If a review is launched in accordance with paragraph 1(d), the following conditions shall apply:

(a) the geographic area in which bidding zone configuration is assessed shall be limited to the control area of the relevant TSO, including interconnectors;

(b) the TSO of the relevant control area shall be the only TSO participating in the review;

(c) the competent regulatory authority shall be the only regulatory authority participating in the review;

(d) the relevant TSO and regulatory authority, respectively, shall give the neighbouring TSOs and regulatory authorities mutually agreed prior notice of the launch of the review, giving reasons; and

(e) the conditions for the review shall be specified, and the results of the review and proposal for the relevant regulatory authorities shall be published.

4. The review process shall consist of two steps.

(a) In the first step, the TSOs participating in a review of bidding zone configuration shall develop the methodology and assumptions that will be used in the review process and propose alternative bidding zone configurations for the assessment.

The proposal on methodology and assumptions and alternative bidding zone configuration shall be submitted to the participating regulatory authorities, which shall be able to require coordinated amendments within three months.

(b) In the second step, the TSOs participating in a review of bidding zone configuration shall:

(i) assess and compare the current bidding zone configuration and each alternative bidding zone configuration using the criteria specified in Article 33;

(ii) hold a consultation in accordance with Article 12 and a workshop regarding the alternative bidding zone configuration proposals compared to the existing bidding zone configuration, including timescales for implementation, unless the bidding zone configuration has negligible impact on neighbouring TSOs' control areas;

(iii) submit a joint proposal to maintain or amend the bidding zone configuration to the participating Member States and the participating regulatory authorities within 15 months of the decision to launch a review.

(c) On receiving the joint proposal to maintain or to amend the bidding zone configuration in accordance with point (iii) above, the participating Member States or, where provided by Member States, the regulatory authorities shall within six months reach an agreement on the proposal to maintain or amend the bidding zone configuration.

5. NEMOs or market participants shall, if requested by TSOs, provide the TSOs participating in a review of a bidding zone with information to enable them to assess bidding zone configurations. This information shall be shared only between the participating TSOs for the sole purpose of assessing bidding zone configurations.

6. The initiative for the review of the bidding zones configuration and its results shall be published by ENTSO for Electricity, or if the review was launched in accordance with paragraph 1(d), by the participating TSO.

Article 33

Criteria for reviewing bidding zone configurations

1. If a review of bidding zone configuration is carried out in accordance with Article 32, at least the following criteria shall be considered:

(a) in respect of network security:

(i) the ability of bidding zone configurations to ensure operational security and security of supply;

(ii) the degree of uncertainty in cross–zonal capacity calculation.

(b) in respect of overall market efficiency:

(i) any increase or decrease in economic efficiency arising from the change;

(ii) market efficiency, including, at least the cost of guaranteeing firmness of capacity, market liquidity, market concentration and market power, the facilitation of effective competition, price signals for building infrastructure, the accuracy and robustness of price signals;

(iii) transaction and transition costs, including the cost of amending existing contractual obligations incurred by market participants, NEMOs and TSOs;

(iv) the cost of building new infrastructure which may relieve existing congestion;

(v) the need to ensure that the market outcome is feasible without the need for extensive application of economically inefficient remedial actions;

(vi) any adverse effects of internal transactions on other bidding zones to ensure compliance with point 1.7 of Annex I to Regulation (EC) No 714/2009;

(vii) the impact on the operation and efficiency of the balancing mechanisms and imbalance settlement processes.

(c) in respect of the stability and robustness of bidding zones:

(i) the need for bidding zones to be sufficiently stable and robust over time;

(ii) the need for bidding zones to be consistent for all capacity calculation time-frames;

(iii) the need for each generation and load unit to belong to only one bidding zone for each market time unit;

(iv) the location and frequency of congestion, if structural congestion influences the delimitation of bidding zones, taking into account any future investment which may relieve existing congestion.

2. A bidding zone review in accordance with Article 32 shall include scenarios which take into account a range of likely infrastructure developments throughout the period of 10 years starting from the year following the year in which the decision to launch the review was taken.

Article 34

Regular reporting on current bidding zone configuration by ENTSO for Electricity and the Agency

1. The Agency shall assess the efficiency of current bidding zone configuration every three years.

It shall:

(a) request ENTSO for Electricity to draft a technical report on current bidding zone configuration; and

(b) draft a market report evaluating the impact of current bidding zone configuration on market efficiency.

2. The technical report referred to in paragraph 1 second subparagraph point (a) shall include at least:

(a) a list of structural congestion and other major physical congestion, including locations and frequency;

(b) an analysis of the expected evolution or removal of physical congestion resulting from investment in networks or from significant changes in generation or in consumption patterns;

(c) an analysis of the share of power flows that do not result from the capacity allocation mechanism, for each capacity calculation region, where appropriate;

(d) congestion incomes and firmness costs;

(e) a scenario encompassing a ten year time-frame.

3. Each TSO shall provide data and analysis to allow the technical report on current bidding zone configuration to be produced in a timely manner.

4. ENTSO for Electricity shall deliver to the Agency the technical report on current bidding zone configuration no later than nine months after the request by the Agency.

5. The technical report on current bidding zone configuration shall cover the last three full calendar years preceding the request by the Agency.

6. Without prejudice to the confidentiality obligations provided for in Article 13, ENTSO for Electricity shall make the technical report available to the public.

7. If the technical or market report reveals inefficiencies in the current bidding zone configuration, the Agency may request TSOs to launch a review of an existing bidding zone configuration in accordance with Article 32(1).

CHAPTER 3

Redispatching and countertrading

Article 35

Coordinated redispatching and countertrading

1. Within 16 months after the regulatory approval on capacity calculation regions referred to in Article 15, all the TSOs in each capacity calculation region shall develop a proposal for a common methodology for coordinated redispatching and countertrading. The proposal shall be subject to consultation in accordance with Article 12.

2. The methodology for coordinated redispatching and countertrading shall include actions of cross-border relevance and shall enable all TSOs in each capacity calculation region to effectively relieve physical congestion irrespective of whether the reasons for the physical congestion fall mainly outside their control area or not. The methodology for coordinated redispatching and countertrading shall address the fact that its application may significantly influence flows outside the TSO's control area.

3. Each TSO may redispatch all available generation units and loads in accordance with the appropriate mechanisms and agreements applicable to its control area, including interconnectors.

By 26 months after the regulatory approval of capacity calculation regions, all TSOs in each capacity calculation region shall develop a report, subject to consultation in accordance with Article 12, assessing the progressive coordination and harmonisation of those mechanisms and agreements and including proposals. The report shall be submitted to their respective regulatory authorities for their assessment. The proposals in the report shall prevent these mechanisms and agreements from distorting the market.

4. Each TSO shall abstain from unilateral or uncoordinated redispatching and countertrading measures of cross-border relevance. Each TSO shall coordinate the use of redispatching and countertrading resources taking into account their impact on operational security and economic efficiency.

5. The relevant generation units and loads shall give TSOs the prices of redispatching and countertrading before redispatching and countertrading resources are committed.

Pricing of redispatching and countertrading shall be based on:

(a) prices in the relevant electricity markets for the relevant time-frame; or

(b) the cost of redispatching and countertrading resources calculated transparently on the basis of incurred costs.

6. Generation units and loads shall *ex-ante* provide all information necessary for calculating the redispatching and countertrading cost to the relevant TSOs. This information shall be shared between the relevant TSOs for redispatching and countertrading purposes only.

CHAPTER 4

Algorithm development

Article 36

General provisions

1. All NEMOs shall develop, maintain and operate the following algorithms:

(a) a price coupling algorithm;

(b) a continuous trading matching algorithm.

2. NEMOs shall ensure that the price coupling algorithm and the continuous trading matching algorithm meet the requirements provided for in Articles 39 and 52 respectively.

3. By 18 months after the entry into force of this Regulation, all NEMOs shall in cooperation with TSOs develop a proposal for a back-up methodology to comply with the obligations set out in Articles 39 and 52 respectively. The proposal for a methodology shall be subject to consultation in accordance with Article 12.

4. Where possible, NEMOs shall use already agreed solutions to efficiently implement the objectives of this Regulation.

Article 37

Algorithm development

1. By eight months after the entry into force of this Regulation:

(a) all TSOs shall jointly provide all NEMOs with a proposal for a common set of requirements for efficient capacity allocation to enable the development of the price coupling algorithm and of the continuous trading matching algorithm. These requirements shall specify functionalities and performance, including deadlines for the delivery of single day-ahead and intraday coupling results and details of the cross-zonal capacity and allocation constraints to be respected;

(b) all NEMOs shall jointly propose a common set of requirements for efficient matching to enable the development of the price coupling algorithm and of the continuous trading matching algorithm.

2. No later than three months after the submission of the TSO and NEMO proposals for a common set of requirements in accordance with paragraph 1, all NEMOs shall develop a proposal for the algorithm in accordance with these requirements. This proposal shall indicate the time limit for the submission of received orders by NEMOs required to perform the MCO functions in accordance with Article 7(1)(b).

3. The proposal referred to in paragraph 2 shall be submitted to all TSOs. If additional time is required to prepare this proposal, all NEMOs shall work together supported by all TSOs for a period of not more than two months to ensure that the proposal complies with paragraphs 1 and 2.

4. The proposals referred to in paragraphs 1 and 2 shall be subject to consultation in accordance with Article 12.

5. All NEMOs shall submit the proposal developed in accordance with paragraphs 2 and 3 to the regulatory authorities for approval by no later than 18 months after the entry into force of this Regulation.

6. No later than two years after the approval of the proposal in accordance with paragraph 5, all TSOs and all NEMOs shall review the operation of the price coupling algorithm and continuous trading matching algorithm and submit the report to the Agency. If requested by the Agency, the review shall then be repeated every second year.

CHAPTER 5

Single day-ahead coupling

Section 1

The price coupling algorithm

Article 38

Objectives of the price coupling algorithm

1. The price coupling algorithm shall produce the results set out in Article 39(2), in a manner which:

(a) aims at maximising economic surplus for single day-ahead coupling for the price-coupled region for the next trading day;

(b) uses the marginal pricing principle according to which all accepted bids will have the same price per bidding zone per market time unit;

(c) facilitates efficient price formation;

(d) respects cross-zonal capacity and allocation constraints;

(e) is repeatable and scalable.

2. The price coupling algorithm shall be developed in such a way that it would be possible to apply it to a larger or smaller number of bidding zones.

Article 39

Inputs and results of the price coupling algorithm

1. In order to produce results, the price coupling algorithm shall use:

(a) allocation constraints established in accordance with Article 23(3);

(b) cross-zonal capacity results validated in accordance with Article 30;

(c) orders submitted in accordance with Article 40.

2. The price coupling algorithm shall produce at least the following results simultaneously for each market time unit:

(a) a single clearing price for each bidding zone and market time unit in EUR/MWh;

(b) a single net position for each bidding zone and each market time unit;

(c) the information which enables the execution status of orders to be determined.

3. All NEMOs shall ensure the accuracy and efficiency of results produced by the single price coupling algorithm.

4. All TSOs shall verify that the results of the price coupling algorithm are consistent with cross-zonal capacity and allocation constraints.

Article 40

Products accommodated

1. No later than 18 months after the entry into force of this Regulation NEMOs shall submit a joint proposal concerning products that can be taken into account in the single day-ahead coupling. NEMOs shall ensure that orders resulting from these products submitted to the price coupling algorithm are expressed in euros and make reference to the market time.

2. All NEMOs shall ensure that the price coupling algorithm is able to accommodate orders resulting from these products covering one market time unit and multiple market time units.

3. By two years after the entry into force of this Regulation and in every second subsequent year, all NEMOs shall consult, in accordance with Article 12:

(a) market participants, to ensure that available products reflect their needs;

(b) all TSOs, to ensure products take due account of operational security;

(c) all regulatory authorities, to ensure that the available products comply with the objectives of this Regulation.

4. All NEMOs shall amend the products if needed pursuant to the results of the consultation referred to in paragraph 3.

Article 41

Maximum and minimum prices

1. By 18 months after the entry into force of this Regulation, all NEMOs shall, in cooperation with the relevant TSOs, develop a proposal on harmonised maximum and minimum clearing prices to be applied in all bidding zones which participate in single day-ahead coupling. The proposal shall take into account an estimation of the value of lost load.

The proposal shall be subject to consultation in accordance with Article 12.

2. All NEMOs shall submit the proposal to the regulatory authorities for approval.

Where a Member State has provided that an authority other than the national regulatory authority has the power to approve maximum and minimum clearing prices at the national level, the regulatory authority shall consult the proposal with the relevant authority as regards its impact on national markets.

After receiving a decision for approval from all regulatory authorities, all NEMOs shall inform the concerned TSOs of that decision without undue delay.

Article 42

Pricing of day-ahead cross-zonal capacity

1. The day-ahead cross-zonal capacity charge shall reflect market congestion and shall amount to the difference between the corresponding day-ahead clearing prices of the relevant bidding zones.

2. No charges, such as imbalance fees or additional fees, shall be applied to day-ahead cross-zonal capacity except for the pricing in accordance with paragraph 1.

Article 43

Methodology for calculating scheduled exchanges resulting from single day-ahead coupling

1. By 16 months after the entry into force of this Regulation, TSOs which intend to calculate scheduled exchanges resulting from single day-ahead coupling shall develop a proposal for a common methodology for this calculation. The proposal shall be subject to consultation in accordance with Article 12.

2. The methodology shall describe the calculation and shall list the information which shall be provided by the relevant NEMOs to the scheduled exchange calculator established in accordance with Article 8(2)(g) and the time limits for delivering this information. The time limit for delivering information shall be no later than 15.30 market time day-ahead.

3. The calculation shall be based on net positions for each market time unit.

4. No later than two years after the approval by the regulatory authorities of the concerned region of the proposal referred to in paragraph 1, TSOs applying scheduled exchanges shall review the methodology. Thereafter, if requested by the competent regulatory authorities, the methodology shall be reviewed every two years.

Article 44

Establishment of fallback procedures

By 16 months after the entry into force of this Regulation, each TSO, in coordination with all the other TSOs in the capacity calculation region, shall develop a proposal for robust and timely fallback procedures to ensure efficient, transparent and non-discriminatory capacity allocation in the event that the single day-ahead coupling process is unable to produce results.

The proposal for the establishment of fallback procedures shall be subject to consultation in accordance with Article 12.

Article 45

Arrangements concerning more than one NEMO in one bidding zone and for interconnectors which are not operated by certified TSOs

1. TSOs in bidding zones where more than one NEMO is designated and/or offers trading services, or where interconnectors which are not operated by TSOs certified according to Article 3 of Regulation (EC) No 714/2009 exist, shall develop a proposal for cross-zonal capacity allocation and other necessary arrangements for such bidding zones in cooperation with concerned TSOs, NEMOs and operators of interconnectors who are not certified as TSOs to ensure that the relevant NEMOs and interconnectors provide the necessary data and financial coverage for such arrangements. These arrangements must allow additional TSOs and NEMOs to join these arrangements.

2. The proposal shall be submitted to the relevant national regulatory authorities for approval within 4 months after more than one NEMO has been designated and/or allowed to offer trading services in a bidding zone or if a new interconnector is not operated by a certified TSO. For existing interconnectors which are not operated by certified TSOs the proposal shall be submitted within four months after entry into force of this Regulation.

Section 2

The single day-ahead coupling process

Article 46

Provision of input data

1. Each coordinated capacity calculator shall ensure that cross-zonal capacity and allocation constraints shall be provided to relevant NEMOs in time to ensure the publication of cross-zonal capacity and of allocation constraints to the market no later than 11.00 market time day-ahead.

2. If a coordinated capacity calculator is unable to provide for cross-zonal capacity and allocation constraints one hour prior to the day-ahead market gate closure time, that coordinated capacity calculator shall notify the relevant NEMOs. These NEMOs shall immediately publish a notice for market participants.

In such cases, cross-zonal capacity and allocation constraints shall be provided by the coordinated capacity calculator no later than 30 minutes before the day-ahead market gate closure time.

Article 47

Operation of single day-ahead coupling

1. The day-ahead market gate opening time shall be at the latest 11:00 market time day-ahead.

2. The day-ahead market gate closure time in each bidding zone shall be noon market time day-ahead. TSOs or NEMOs in the region based on the CEE region or its neighbouring countries may set a different gate closure time until this region has joined single day-ahead coupling.

3. Market participants shall submit all orders to the relevant NEMOs before day-ahead market gate closure time, in accordance with Articles 39 and 40.

4. Each NEMO shall submit the orders received in accordance with paragraph 3 to perform the MCO functions in accordance with Article 7(2) by no later than a time specified by all NEMOs in the proposal for a single price coupling algorithm set out in Article 37(5).

5. Orders matched in single day-ahead coupling shall be considered firm.

6. MCO functions shall ensure anonymity of submitted orders.

Article 48

Delivery of results

1. No later than by the time specified by all TSOs in the requirements set out in Article 37(1)(a), all NEMOs performing MCO functions shall deliver the single day-ahead coupling results:

(a) to all TSOs, all coordinated capacity calculators and all NEMOs, for the results specified in Article 39(2)(a) and (b);

(b) to all NEMOs, for the results specified in Article 39(2)(c).

2. Each TSO shall verify that the single day-ahead coupling results of the price coupling algorithm referred to in Article 39(2)(b) have been calculated in accordance with the allocation constraints and validated cross-zonal capacity.

3. Each NEMO shall verify that the single day-ahead coupling results of the price coupling algorithm referred to in Article 39(2)(c) have been calculated in accordance with the orders.

4. Each NEMO shall inform market participants on the execution status of their orders without unjustifiable delay.

Article 49

Calculation of scheduled exchanges resulting from single day-ahead coupling

1. Each scheduled exchange calculator shall calculate scheduled exchanges between bidding zones for each market time unit in accordance with the methodology established in Article 43.

2. Each scheduled exchange calculator shall notify relevant NEMOs, central counter parties, shipping agents and TSOs of the agreed scheduled exchanges.

Article 50

Initiation of fallback procedures

1. In the event that all NEMOs performing MCO functions are unable to deliver part or all of the results of the price coupling algorithm by the time specified in Article 37(1)(a), the fallback procedures established in accordance with Article 44 shall apply.

2. In cases where there is a risk that all NEMOs performing MCO functions are unable to deliver part or all of the results within the deadline, all NEMOs shall notify all TSOs as soon as the risk is identified. All NEMOs performing MCO functions shall immediately publish a notice to market participants that fallback procedures may be applied.

CHAPTER 6

Single intraday coupling

Section 1

Objectives, conditions and results of single intraday coupling

Article 51

Objectives of the continuous trading matching algorithm

1. From the intraday cross-zonal gate opening time until the intraday cross-zonal gate closure time, the continuous trading matching algorithm shall determine which orders to select for matching such that matching:

(a) aims at maximising economic surplus for single intraday coupling per trade for the intraday market time-frame by allocating capacity to orders for which it is feasible to match in accordance with the price and time of submission;

(b) respects the allocation constraints provided in accordance with Article 58(1);

(c) respects the cross-zonal capacity provided in accordance with Article 58(1);

(d) respects the requirements for the delivery of results set out in Article 60;

(e) is repeatable and scalable.

2. The continuous trading matching algorithm shall produce the results provided for in Article 52 and correspond to the product capabilities and functionalities set out in Article 53.

Article 52

Results of the continuous trading matching algorithm

1. All NEMOs, as part of their MCO function, shall ensure that the continuous trading matching algorithm produces at least the following results:

(a) the execution status of orders and prices per trade;

(b) a single net position for each bidding zone and market time unit within the intraday market.

2. All NEMOs shall ensure the accuracy and efficiency of results produced by the continuous trading matching algorithm.

3. All TSOs shall verify that the results of the continuous trading matching algorithm are consistent with cross-zonal capacity and allocation constraints in accordance with Article 58(2).

Article 53

Products accommodated

1. No later than 18 months after the entry into force of this Regulation NEMOs shall submit a joint proposal concerning products that can be taken into account in the single intraday coupling. NEMOs shall ensure that all orders resulting from these products submitted to enable the MCO functions to be performed in accordance with Article 7 are expressed in euros and make reference to the market time and the market time unit.

2. All NEMOs shall ensure that orders resulting from these products are compatible with the characteristics of cross-zonal capacity, allowing them to be matched simultaneously.

3. All NEMOs shall ensure that the continuous trading matching algorithm is able to accommodate orders covering one market time unit and multiple market time units.

4. By two years after the entry into force of this Regulation and in every second subsequent year, all NEMOs shall consult in accordance with Article 12:

(a) market participants, to ensure that available products reflect their needs;

(b) all TSOs, to ensure products take due account of operational security;

(c) all regulatory authorities, to ensure that the available products comply with the objectives of this Regulation.

5. All NEMOs shall amend the products if needed pursuant to the results of the consultation referred to in paragraph 4.

Article 54

Maximum and minimum prices

1. By 18 months after the entry into force of this Regulation, all NEMOs shall, in cooperation with the relevant TSOs, develop a proposal on harmonised maximum and minimum clearing prices to be applied in all bidding zones which participate in single intraday coupling. The proposal shall take into account an estimation of the value of lost load.

The proposal shall be subject to consultation in accordance with Article 12.

2. All NEMOs shall submit the proposal to all regulatory authorities for approval. Where a Member State has provided that an authority other than the national regulatory authority has the power to approve maximum and minimum clearing prices at the national level, the regulatory authority shall consult the proposal with the relevant authority as regards its impact on national markets.

3. After receiving a decision from the regulatory authorities, all NEMOs shall inform the concerned TSOs of that decision without unjustifiable delay.

Article 55

Pricing of intraday capacity

1. Once applied, the single methodology for pricing intraday cross-zonal capacity developed in accordance with Article 55(3) shall reflect market congestion and shall be based on actual orders.

2. Prior to the approval of the single methodology for pricing intraday cross-zonal capacity set out in paragraph 3, TSOs may propose an intraday cross-zonal capacity allocation mechanism with reliable pricing consistent with the requirements of paragraph 1 for approval by the regulatory authorities of the relevant Member States. This mechanism shall ensure that the price of intraday cross-zonal capacity is available to the market participants at the time of matching the orders.

3. By 24 months after the entry into force of this Regulation, all TSOs shall develop a proposal for a single methodology for pricing intraday cross-zonal capacity. The proposal shall be subject to consultation in accordance with Article 12.

4. No charges, such as imbalance fees or additional fees, shall be applied to intraday cross-zonal capacity except for the pricing in accordance with paragraphs 1, 2 and 3.

Article 56

Methodology for calculating scheduled exchanges resulting from single intraday coupling

1. By 16 months after the entry into force of this Regulation, the TSOs which intend to calculate scheduled exchanges resulting from single intraday coupling shall develop a proposal for a common methodology for this calculation.

The proposal shall be subject to consultation in accordance with Article 12.

2. The methodology shall describe the calculation and, where required, shall list the information which the relevant NEMOs shall provide to the scheduled exchange calculator and the time limits for delivering this information.

3. The calculation of scheduled exchanges shall be based on net positions as specified in Article 52(1)(b).

4. No later than two years after the approval by the regulatory authorities of the concerned region of the proposal referred to in paragraph 1, the relevant TSOs shall review the methodology. Thereafter, if requested by the competent regulatory authorities, the TSOs shall review the methodology every two years.

Article 57

Arrangements concerning more than one NEMO in one bidding zone and for interconnectors which are not operated by certified TSOs

1. TSOs in bidding zones where more than one NEMO is designated and/or offers trading services, or where interconnectors which are not operated by TSOs certified according to Article 3 of Regulation (EC) No 714/2009 exist, shall develop a proposal for cross-zonal capacity allocation and other necessary arrangements for such bidding zones in cooperation with concerned TSOs, NEMOs and operators of interconnectors who are not certified as TSOs to ensure that the relevant NEMOs and interconnectors provide the necessary data and financial coverage for such arrangements. These arrangements must allow additional TSOs and NEMOs to join these arrangements.

2. The proposal shall be submitted for approval by the relevant national regulatory authorities within 4 months of more than one NEMO being designated and/or allowed to offer trading services in a bidding zone or if a new interconnector is not operated by a certified TSO. For existing interconnectors which are not operated by certified TSOs the proposal shall be submitted within 4 months after entry into force of this Regulation.

Section 2

The single intraday coupling process

Article 58

Provision of input data

1. Each coordinated capacity calculator shall ensure that cross-zonal capacity and allocation constraints are provided to the relevant NEMOs no later than 15 minutes before the intraday cross-zonal gate opening time.

2. If updates to cross-zonal capacity and allocation constraints are required, due to operational changes on the transmission system, each TSO shall notify the coordinated capacity calculators in its capacity calculation region. The coordinated capacity calculators shall then notify the relevant NEMOs.

3. If any coordinated capacity calculator is unable to comply with paragraph 1, that coordinated capacity calculator shall notify the relevant NEMOs. These NEMOs shall publish a notice to all market participants without unjustifiable delay.

Article 59

Operation of single intraday coupling

1. By 16 months after the entry into force of this Regulation, all TSOs shall be responsible for proposing the intraday cross-zonal gate opening and intraday cross-zonal gate closure times. The proposal shall be subject to consultation in accordance with Article 12.

2. The intraday cross-zonal gate closure time shall be set in such a way that it:

(a) maximises market participants' opportunities for adjusting their balances by trading in the intraday market time-frame as close as possible to real time; and

(b) provides TSOs and market participants with sufficient time for their scheduling and balancing processes in relation to network and operational security.

3. One intraday cross-zonal gate closure time shall be established for each market time unit for a given bidding zone border. It shall be at most one hour before the start of the relevant market time unit and shall take into account the relevant balancing processes in relation to operational security.

4. The intraday energy trading for a given market time unit for a bidding zone border shall start at the latest at the intraday cross-zonal gate opening time of the relevant bidding zone borders and shall be allowed until the intraday cross-zonal gate closure time.

5. Before the intraday cross-zonal gate closure time, market participants shall submit to relevant NEMOs all the orders for a given market time unit. All NEMOs shall submit the orders for a given market time unit for single matching immediately after the orders have been received from market participants.

6. Orders matched in single intraday coupling shall be considered firm.

7. MCO functions shall ensure the anonymity of orders submitted via the shared order book.

Article 60

Delivery of results

1. All NEMOs performing MCO functions shall deliver the continuous trading matching algorithm results:

(a) to all other NEMOs, for results on the execution status per trade specified in Article 52(1)(a);

(b) to all TSOs and scheduled exchange calculators, for results single net positions specified in Article 52(1)(b).

2. If, in accordance with paragraph 1(a), any NEMO, for reasons outside its responsibility, is unable to deliver these continuous trading matching algorithm results, it shall notify all other NEMOs.

3. If, in accordance with paragraph 1(b), any NEMO, for reasons outside its responsibility, is unable to deliver these continuous trading matching algorithm results, it shall notify all TSOs and each scheduled exchange calculator as soon as reasonably practicable. All NEMOs shall notify the market participants concerned.

4. All NEMOs shall send, without undue delay, the necessary information to market participants to ensure that the actions specified in Articles 68 and 73(3) can be undertaken.

Article 61

Calculation of scheduled exchanges resulting from single intraday coupling

1. Each scheduled exchange calculator shall calculate scheduled exchanges between bidding zones for each market time unit in accordance with the methodology established in accordance with Article 56.

2. Each scheduled exchange calculator shall notify the relevant NEMOs, central counter parties, shipping agents, and TSOs of the agreed scheduled exchanges.

Article 62

Publication of market information

1. As soon as the orders are matched, each NEMO shall publish for relevant market participants at least the status of execution of orders and prices per trade produced by the continuous trading matching algorithm in accordance with Article 52(1)(a).

2. Each NEMO shall ensure that information on aggregated executed volumes and prices is made publicly available in an easily accessible format for at least 5 years. The information to be published shall be proposed by all NEMOS within the proposal for continuous trading matching algorithm pursuant to Article 37(5).

Article 63

Complementary regional auctions

1. By 18 months after the entry into force of this Regulation, the relevant NEMOs and TSOs on bidding zone borders may jointly submit a common proposal for the design and implementation of complementary regional intraday auctions. The proposal shall be subject to consultation in accordance with Article 12.

2. Complementary regional intraday auctions may be implemented within or between bidding zones in addition to the single intraday coupling solution referred to in Article 51. In order to hold regional intraday auctions, continuous trading within and between the relevant bidding zones may be stopped for a limited period of time before the intraday cross-zonal gate closure time, which shall not exceed the minimum time required to hold the auction and in any case 10 minutes.

3. For complementary regional intraday auctions, the methodology for pricing intraday cross-zonal capacity may differ from the methodology established in accordance with Article 55(3) but it shall nevertheless meet the principles provided for in Article 55(1).

4. The competent regulatory authorities may approve the proposal for complementary regional intraday auctions if the following conditions are met:

(a) regional auctions shall not have an adverse impact on the liquidity of the single intraday coupling;

(b) all cross-zonal capacity shall be allocated through the capacity management module;

(c) the regional auction shall not introduce any undue discrimination between market participants from adjacent regions;

(d) the timetables for regional auctions shall be consistent with single intraday coupling to enable market participants to trade as close as possible to real-time;

(e) regulatory authorities shall have consulted the market participants in the Member States concerned.

5. At least every two years after the decision on complementary regional auctions, the regulatory authorities of the Member States concerned shall review the compatibility of any regional solutions with single intraday coupling to ensure that the conditions above continue to be fulfilled.

Section 3

Transitional intraday arrangements

Article 64

Provisions relating to explicit allocation

1. Where jointly requested by the regulatory authorities of the Member States of each of the bidding zone borders concerned, the TSOs concerned shall also provide explicit allocation, in addition to implicit allocation, that is to say, capacity allocation separate from the electricity trade, via the capacity management module on bidding zone borders.

2. The TSOs on the bidding zone borders concerned shall jointly develop a proposal on the conditions that shall be fulfilled by market participants to participate in explicit allocation. The proposal shall be subject to the joint approval by the regulatory authorities of the Member States of each of the bidding zone borders concerned.

3. When establishing the capacity management module, discrimination shall be avoided when simultaneously allocating capacity implicitly and explicitly. The capacity management module shall determine which orders to select for matching and which explicit capacity requests to accept, according to a ranking of price and time of entrance.

Article 65

Removal of explicit allocation

1. The NEMOs concerned shall cooperate closely with the TSOs concerned and shall consult market participants in accordance with Article 12 in order to translate the needs of market participants linked to explicit capacity allocation rights into non-standard intraday products.

2. Prior to deciding on the removal of explicit allocation, the regulatory authorities of the Member States of each of the bidding zone borders concerned shall jointly organise a consultation to assess whether the proposed non-standard intraday products meet the market participants' needs for intraday trading.

3. The competent regulatory authorities of the Member States of each of the bidding zone borders concerned shall jointly approve the introduced non-standard products and the removal of explicit allocation.

Article 66

Provisions relating to intraday arrangements

1. Market participants shall ensure the completion of nomination, clearing and settlement related to explicit allocation of cross-zonal capacity.

2. Market participants shall fulfil any financial obligations, relating to clearing and settlement arising from explicit allocation.

3. The participating TSOs shall publish relevant information on the interconnections to which explicit allocation is applicable, including the cross-zonal capacity for explicit allocation.

Article 67

Explicit requests for capacity

A request for explicit cross-zonal capacity may be submitted by a market participant only for an interconnection where the explicit allocation is applicable. For each request for explicit capacity the market participant shall submit the volume and the price to the capacity management module. The price and volume of explicit allocated capacity shall be made publicly available by the relevant TSOs.

CHAPTER 7

Clearing and settlement for single day-ahead and intraday coupling

Article 68

Clearing and settlement

1. The central counter parties shall ensure clearing and settlement of all matched orders in a timely manner. The central counter parties shall act as the counter party to market participants for all their trades with regard to the financial rights and obligations arising from these trades.

2. Each central counter party shall maintain anonymity between market participants.

3. Central counter parties shall act as counter party to each other for the exchange of energy between bidding zones with regard to the financial rights and obligations arising from these energy exchanges.

4. Such exchanges shall take into account:

(a) net positions produced in accordance with Articles 39(2)(b) and 52(1)(b);

(b) scheduled exchanges calculated in accordance with Articles 49 and 61.

5. Each central counter party shall ensure that for each market time unit:

(a) across all bidding zones, taking into account, where appropriate, allocation constraints, there are no deviations between the sum of energy transferred out of all surplus bidding zones and the sum of energy transferred into all deficit bidding zones;

(b) electricity exports and electricity imports between bidding zones equal each other, with any deviations resulting only from considerations of allocation constraints, where appropriate.

6. Notwithstanding paragraph 3, a shipping agent may act as a counter party between different central counter parties for the exchange of energy, if the parties concerned conclude a specific agreement to that effect. If no agreement is reached, the shipping arrangement shall be decided by the regulatory authorities responsible for the bidding zones between which the clearing and settlement of the exchange of energy is needed.

7. All central counter parties or shipping agents shall collect congestion incomes arising from the single day-ahead coupling specified in Articles 46 to 48 and from the single intraday coupling specified in Articles 58 to 60.

8. All central counter parties or shipping agents shall ensure that collected congestion incomes are transferred to the TSOs no later than two weeks after the date of settlement.

9. If the timing of payments is not harmonised between two bidding zones, the Member States concerned shall ensure that an entity is appointed to manage the timing mismatch and to bear the relevant costs.

CHAPTER 8

Firmness of allocated cross-zonal capacity

Article 69

Proposal for day-ahead firmness deadline

By 16 months after the entry into force of this Regulation, all TSOs shall develop a common proposal for a single day-ahead firmness deadline, which shall not be shorter than half an hour before the day-ahead market gate closure time. The proposal shall be subject to consultation in accordance with Article 12.

Article 70

Firmness of day-ahead capacity and allocation constraints

1. Prior to the day-ahead firmness deadline, each coordinated capacity calculator may adjust cross-zonal capacity and allocation constraints provided to relevant NEMOs.

2. After the day-ahead firmness deadline, all cross-zonal capacity and allocation constraints shall be firm for day-ahead capacity allocation unless the requirements of Article 46(2) are met, in which case cross-zonal capacity and allocation constraints shall be firm as soon as they are submitted to relevant NEMOs.

3. After the day-ahead firmness deadline, cross-zonal capacity which has not been allocated may be adjusted for subsequent allocations.

Article 71

Firmness of intraday capacity

Cross-zonal intraday capacity shall be firm as soon as it is allocated.

Article 72

Firmness in the event of force majeure **or emergency situations**

1. In the event of *force majeure* or an emergency situation referred to in Article 16(2) of Regulation (EC) No 714/2009, where the TSO shall act in an expeditious manner and redispatching or countertrading is not possible, each TSO shall have the right to curtail allocated cross-zonal capacity. In all cases, curtailment shall be undertaken in a coordinated manner following liaison with all directly concerned TSOs.

2. A TSO which invokes *force majeure* or an emergency situation shall publish a notice explaining the nature of the *force majeure* or the emergency situation and its probable duration. This notice shall be made available to the market participants concerned through NEMOs. If capacity is allocated explicitly to market participants, the TSO invoking *force majeure* or an emergency situation shall send notice directly to contractual parties holding cross-zonal capacity for the relevant market time-frame.

3. If allocated capacity is curtailed because of *force majeure* or an emergency situation invoked by a TSO, the TSO shall reimburse or provide compensation for the period of *force majeure* or the emergency situation, in accordance with the following requirements:

(a) if there is implicit allocation, central counter parties or shipping agents shall not be subject to financial damage or financial benefit arising from any imbalance created by such curtailment;

(b) in the event of *force majeure*, if capacity is allocated via explicit allocation, market participants shall be entitled to reimbursement of the price paid for the capacity during the explicit allocation process;

(c) in an emergency situation, if capacity is allocated via explicit allocation, market participants shall be entitled to compensation equal to the price difference of relevant markets between the bidding zones concerned in the relevant time-frame; or

(d) in an emergency situation, if capacity is allocated via explicit allocation but the bidding zone price is not calculated in at least one of the two relevant bidding zones in the relevant time-frame, market participants shall be entitled to reimbursement of the price paid for capacity during the explicit allocation process.

4. The TSO invoking *force majeure* or an emergency situation shall limit the consequences and duration of the *force majeure* situation or emergency situation.

5. Where a Member State has so provided, upon request by the TSO concerned the national regulatory authority shall assess whether an event qualifies as *force majeure*.

TITLE III

COSTS

CHAPTER 1

Congestion income distribution methodology for single day-ahead and intraday coupling

Article 73

Congestion income distribution methodology

1. By 12 months after the entry into force of this Regulation, all TSOs shall develop a proposal for a methodology for sharing congestion income.

2. The methodology developed in accordance with paragraph 1 shall:

(a) facilitate the efficient long-term operation and development of the electricity transmission system and the efficient operation of the electricity market of the Union;

(b) comply with the general principles of congestion management provided for in Article 16 of Regulation (EC) No 714/2009;

(c) allow for reasonable financial planning;

(d) be compatible across time-frames;

(e) establish arrangements to share congestion income deriving from transmission assets owned by parties other than TSOs.

3. TSOs shall distribute congestion incomes in accordance with the methodology in paragraph 1 as soon as reasonably practicable and no later than one week after the congestion incomes have been transferred in accordance with Article 68(8).

CHAPTER 2

Redispatching and countertrading cost sharing methodology for single day-ahead and intraday coupling

Article 74

Redispatching and countertrading cost sharing methodology

1. No later than 16 months after the decision on the capacity calculation regions is taken, all TSOs in each capacity calculation region shall develop a proposal for a common methodology for redispatching and countertrading cost sharing.

2. The redispatching and countertrading cost sharing methodology shall include cost-sharing solutions for actions of cross-border relevance.

3. Redispatching and countertrading costs eligible for cost sharing between relevant TSOs shall be determined in a transparent and auditable manner.

4. The redispatching and countertrading cost sharing methodology shall at least:

(a) determine which costs incurred from using remedial actions, for which costs have been considered in the capacity calculation and where a common framework on the use of such actions has been established, are eligible for sharing between all the TSOs of a capacity calculation region in accordance with the capacity calculation methodology set out in Articles 20 and 21;

(b) define which costs incurred from using redispatching or countertrading to guarantee the firmness of cross-zonal capacity are eligible for sharing between all the TSOs of a capacity calculation region in accordance with the capacity calculation methodology set out in Articles 20 and 21;

(c) set rules for region-wide cost sharing as determined in accordance with points (a) and (b).

5. The methodology developed in accordance with paragraph 1 shall include:

(a) a mechanism to verify the actual need for redispatching or countertrading between the TSOs involved;

(b) an *ex post* mechanism to monitor the use of remedial actions with costs;

(c) a mechanism to assess the impact of the remedial actions, based on operational security and economic criteria;

(d) a process allowing improvement of the remedial actions;

(e) a process allowing monitoring of each capacity calculation region by the competent regulatory authorities.

6. The methodology developed in accordance with paragraph 1 shall also:

(a) provide incentives to manage congestion, including remedial actions and incentives to invest effectively;

(b) be consistent with the responsibilities and liabilities of the TSOs involved;

(c) ensure a fair distribution of costs and benefits between the TSOs involved;

(d) be consistent with other related mechanisms, including at least:

(i) the methodology for sharing congestion income set out in Article 73;

(ii) the inter-TSO compensation mechanism, as set out in Article 13 of Regulation (EC) No 714/2009 and Commission Regulation (EU) No 838/2010 [1];

(e) facilitate the efficient long-term development and operation of the pan-European interconnected system and the efficient operation of the pan-European electricity market;

(f) facilitate adherence to the general principles of congestion management as set out in Article 16 of Regulation (EC) No 714/2009;

(g) allow reasonable financial planning;

(h) be compatible across the day-ahead and intraday market time-frames; and

(i) comply with the principles of transparency and non-discrimination.

7. By 31 December 2018, all TSOs of each capacity calculation region shall further harmonise as far as possible between the regions the redispatching and countertrading cost sharing methodologies applied within their respective capacity calculation region.

CHAPTER 3

Capacity allocation and congestion management cost recovery

Article 75

General provisions on cost recovery

1. Costs relating to the obligations imposed on TSOs in accordance with Article 8, including the costs specified in Article 74 and Articles 76 to 79, shall be assessed by the competent regulatory authorities. Costs assessed as reasonable, efficient and proportionate shall be recovered in a timely manner through network tariffs or other appropriate mechanisms as determined by the competent regulatory authorities.

2. Member States' share of the common costs referred to in Article 80(2)(a), regional costs referred to in Article 80(2)(b) and national costs referred to in Article 80(2)(c) assessed as reasonable, efficient and proportionate shall be recovered through NEMO fees, network tariffs or other appropriate mechanisms as determined by the competent regulatory authorities.

3. If requested by the regulatory authorities, relevant TSOs, NEMOs and delegates in accordance with Article 78 shall, within three months of the request, provide information necessary to facilitate the assessment of the costs incurred.

[1] Commission Regulation (EU) No 838/2010 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and common regulatory approach to transmission charging (OJ L 250, 24.9.2010, p. 5).

Article 76

Costs of establishing, amending and operating single day-ahead and intraday coupling

1. All NEMOs shall bear the following costs:

(a) common, regional and national costs of establishing, updating or further developing the price coupling algorithm and single day-ahead coupling;

(b) common, regional and national costs of establishing, updating or further developing the continuous trading matching algorithm and single intraday coupling;

(c) common, regional and national costs of operating single day-ahead and intraday coupling.

2. Subject to agreement with the NEMOs concerned, TSOs may make a contribution to the costs provided for in paragraph 1 subject to approval by the relevant regulatory authorities. In such cases, within two months of receiving a forecast from the NEMOs concerned, each TSO shall be entitled to provide a cost contribution proposal to the relevant regulatory authority for approval.

3. The NEMOs concerned shall be entitled to recover costs in accordance with paragraph 1 which have not been borne by TSOs in accordance with paragraph 2 by means of fees or other appropriate mechanisms only if the costs are reasonable and proportionate, through national agreements with the competent regulatory authority.

Article 77

Clearing and settlement costs

1. All costs incurred by central counter parties and shipping agents shall be recoverable by means of fees or other appropriate mechanisms if they are reasonable and proportionate.

2. The central counter parties and shipping agents shall seek efficient clearing and settlement arrangements avoiding unnecessary costs and reflecting the risk incurred. The cross-border clearing and settlement arrangements shall be subject to approval by the relevant national regulatory authorities.

Article 78

Costs of establishing and operating the coordinated capacity calculation process

1. Each TSO shall individually bear the costs of providing inputs to the capacity calculation process.

2. All TSOs shall bear jointly the costs of merging the individual grid models.

All TSOs in each capacity calculation region shall bear the costs of establishing and operating the coordinated capacity calculators.

3. Any costs incurred by market participants in meeting the requirements of this Regulation shall be borne by those market participants.

Article 79

Costs of ensuring firmness

The costs of ensuring firmness in accordance with Articles 70(2) and 71 shall be borne by the relevant TSOs, to the extent possible in accordance with Article 16(6)(a) of Regulation (EC) No 714/2009. These costs shall include the costs from compensation mechanisms associated with ensuring the firmness of cross-zonal capacities as well as the costs of redispatching, countertrading and imbalance associated with compensating market participants.

Article 80

Cost sharing between NEMOs and TSOs in different Member States

1. All relevant NEMOs and TSOs shall provide a yearly report to the regulatory authorities in which the costs of establishing, amending and operating single day-ahead and intraday coupling are explained in detail. This report shall be published by the Agency taking due account of sensitive commercial information. Costs directly related to single day-ahead and intraday coupling shall be clearly and separately identified and auditable. The report shall also provide full details of contributions made to NEMO costs by TSOs in accordance with Article 76(2).

2. The costs referred to in paragraph 1 shall be broken down into:

(a) common costs resulting from coordinated activities of all NEMOs or TSOs participating in the single day-ahead and intraday coupling;

(b) regional costs resulting from activities of NEMOs or TSOs cooperating in a certain region;

(c) national costs resulting from activities of the NEMOs or TSOs in that Member State.

3. Common costs referred to in paragraph 2(a) shall be shared among the TSOs and NEMOs in the Member States and third countries participating in the single day-ahead and intraday coupling. To calculate the amount to be paid by the TSOs and NEMOs in each Member State and, if applicable, third countries, one eighth of the common cost shall be divided equally between each Member State and third country, five eighths shall be divided between each Member State and third country proportionally to their consumption, and two eighths shall be divided equally between the participating NEMOs. To take into account changes in the common costs or changes in the participating TSOs and NEMOs, the calculation of common costs shall be regularly adapted.

4. NEMOs and TSOs cooperating in a certain region shall jointly agree on a proposal for the sharing of regional costs in accordance with paragraph 2(b). The proposal shall then be individually approved by the competent national authorities of each of the Member States in the region. NEMOs and TSOs cooperating in a certain region may alternatively use the cost sharing arrangements set out in paragraph 3.

5. The cost sharing principles shall apply to costs incurred from the entry into force of this Regulation. This is without prejudice to existing solutions used for the development of single day-ahead and intraday coupling and costs incurred prior to the entry into force of this Regulation shall be shared among the NEMOs and TSOs based on the existing agreements governing such solutions.

TITLE IV

DELEGATION OF TASKS AND MONITORING

Article 81

Delegation of tasks

1. A TSO or NEMO may delegate all or part of any task assigned to it under this Regulation to one or more third parties in the case the third party can carry out the respective function at least as effectively as the delegating entity. The delegating entity shall remain responsible for ensuring compliance with the obligations under this Regulation, including ensuring access to information necessary for monitoring by the regulatory authority.

2. Prior to the delegation, the third party concerned shall have clearly demonstrated to the delegating party its ability to meet each of the obligations of this Regulation.

3. In the event that all or part of any task specified in this Regulation is delegated to a third party, the delegating party shall ensure that suitable confidentiality agreements in accordance with the confidentiality obligations of the delegating party have been put in place prior to delegation.

Article 82

Monitoring of the implementation of single day-ahead and intraday coupling

1. The entity or entities performing the MCO functions shall be monitored by the regulatory authorities or relevant authorities of the territory where they are located. Other regulatory authorities or relevant authorities, and the Agency, shall contribute to the monitoring where adequate. The regulatory authorities or relevant authorities primarily responsible for monitoring a NEMO and the MCO functions shall fully cooperate and shall provide access to information for other regulatory authorities and the Agency in order to ensure proper monitoring of single day-ahead and intraday coupling in accordance with Article 38 of Directive 2009/72/EC.

2. Monitoring of the implementation of single day-ahead and intraday coupling by ENTSO for Electricity in accordance with Article 8(8) of Regulation (EC) No 714/2009 shall in particular cover the following matters:

(a) progress and potential problems with the implementation of single day-ahead and intraday coupling, including the choice of different available options in each country;

(b) preparing the report on capacity calculation and allocation in accordance with Article 31(1);

(c) the efficiency of current bidding zone configuration in coordination with the Agency in accordance with Article 34;

(d) the effectiveness of the operation of the price coupling algorithm and of the continuous trading matching algorithm in cooperation with NEMOs in accordance with Article 37(6);

(e) the effectiveness of the criterion concerning the estimation of the value of lost load, in accordance with Articles 41(1) and 54(1); and

(f) the review of the methodology for calculating scheduled exchanges resulting from single day-ahead coupling in accordance with Article 43(4).

3. ENTSO for Electricity shall submit a monitoring plan which includes the reports to be prepared and any updates in accordance with paragraph 2, to the Agency for an opinion by six months after entry into force of this Regulation.

4. The Agency, in cooperation with ENTSO for Electricity, shall draw up by six months after the entry into force of this Regulation a list of the relevant information to be communicated by ENTSO for Electricity to the Agency in accordance with Articles 8(9) and 9(1) of Regulation (EC) No 714/2009. The list of relevant information may be subject to updates. ENTSO for Electricity shall maintain a comprehensive, standardised format, digital data archive of the information required by the Agency.

5. All TSOs shall submit to ENTSO for Electricity the information required to perform the tasks in accordance with paragraphs 2 and 4.

6. NEMOs, market participants and other relevant organisations regarding single day-ahead and intraday coupling shall, at the joint request of the Agency and the ENTSO for Electricity, submit to the ENTSO for Electricity the information required for monitoring in accordance with paragraph 2 and 4, except for information already obtained by the regulatory authorities, the Agency or the ENTSO for Electricity in the context of their respective implementation monitoring tasks.

TITLE V

TRANSITIONAL AND FINAL PROVISIONS

Article 83

Transitional provisions for Ireland and Northern Ireland

1. Except for Articles 4, 5 and 6 and participation in the development of terms and conditions or methodologies, for which the respective deadlines shall apply, the requirements of this Regulation shall not apply in Ireland and Northern Ireland until 31 December 2017.

2. From the date of the entry into force of this Regulation until 31 December 2017, Ireland and Northern Ireland shall implement preparatory transitional arrangements. Those transitional arrangements shall:

(a) facilitate the transition to full implementation of and full compliance with this Regulation, and include all necessary preparatory measures for full implementation of and full compliance with this Regulation, by 31 December 2017;

(b) guarantee a reasonable degree of integration with the markets in adjacent jurisdictions;

(c) provide for at least:

(i) allocation of interconnector capacity in an explicit day-ahead auction and in at least two implicit intraday auctions;

(ii) joint nomination of interconnection capacity and energy at the day-ahead market time-frame;

(iii) application of the 'Use-It-Or-Lose-It' or 'Use-It-Or-Sell-It' principle, as specified in point 2.5 of Annex I to Regulation (EC) No 714/2009, to capacity not used at the day-ahead market time-frame.

(d) ensure fair and non-discriminatory pricing of interconnector capacity in the implicit intraday auctions;

(e) put in place fair, transparent and non-discriminatory compensation mechanisms for ensuring firmness;

(f) set out a detailed roadmap, approved by the regulatory authorities for Ireland and Northern Ireland, with milestones for achieving full implementation of and compliance with this Regulation;

(g) be subject to a consultation process, involving all relevant parties and give the utmost consideration to the consultation's outcome;

(h) be justified on the basis of a cost-benefit analysis;

(i) not unduly affect other jurisdictions.

3. Regulatory authorities for Ireland and Northern Ireland shall provide to the Agency at least quarterly, or upon the Agency's request, any information required for assessing the transitional arrangements for the electricity market on the island of Ireland and the progress towards achieving full implementation of and compliance with this Regulation.

Article 84

Entry into force

This Regulation shall enter into force on the twentieth day following that of its publication in the *Official Journal of the European Union*.

This Regulation shall be binding in its entirety and directly applicable in all Member States.

Done at Brussels, 24 July 2015.

For the Commission

The President

Jean-Claude JUNCKER

Annex I

Harmonised maximum and minimum clearing prices for single day-ahead coupling in accordance with Article 41(1) of Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (CACM Regulation)

14 November 2017

TABLE OF CONTENTS

Whereas

(1) This document sets the harmonised maximum and minimum clearing prices ('HMMCP') in single day-ahead coupling ('SDAC') in accordance with Article 41 of the CACM Regulation.

(2) In accordance with Article 41(1) of the CACM Regulation, the HMMCP for SDAC shall take into account an estimation of the value of lost load ('VoLL'). The objective of this requirement is to ensure that the HMMCP for SDAC does not impose barriers on free price formation. This document provides for the amendment rule of HMMCP for SDAC, which is expected to achieve the same goal, i.e. to minimise the likelihood that HMMCP for SDAC impose barriers on free price formation. The HMMCP for SDAC therefore implicitly take into account the VoLL as the amendment rule is expected to gradually increase the HMMCP for SDAC to a level, which represents the VoLL as determined by the market participants' willingness to pay.

(3) The amendment rule for the harmonised maximum clearing price for SDAC includes a transition period over which the clearing price is still capped at the value of the harmonised maximum clearing price for SDAC before the amendment, while the amended value serves as a reference for triggering any further amendments of the harmonised maximum clearing price for SDAC. This transition period aims to give time to market participants to adjust to the amended value of the harmonised maximum clearing price for SDAC, while minimising the impact on free price formation.

(4) The HMMCP for SDAC take into account the general objectives of capacity allocation and congestion management cooperation described in Article 3 of the CACM Regulation.

(5) This document fulfils the objective of 'promoting effective competition in the generation, trading and supply of electricity' as the HMMCP for SDAC have been set at levels that do not restrict effective competition in the generation, consumption, trading or supply in the organised wholesale market. These limits have been applied since some time in auction-based day-ahead couplings, e.g. MRC and 4MMC covering multiple Bidding Zones, and have proven to be adequate.

(6) This document fulfils the objective of 'ensuring operational security' by harmonising maximum and minimum clearing prices as well as removing barriers for free price formation. This promotes flexibility and thereby contributes to the operational security, as well as security of supply.

(7) This document fulfils the objective of 'optimising the calculation and allocation of cross-zonal capacity', and also the objective of 'optimal use of the transmission infrastructure', by removing the barriers for free price formation which effectively optimises the allocation of cross-zonal capacities and the use of transmission infrastructure.

(8) This document fulfils, or rather is deemed to have no negative impact on, the objective of 'ensuring fair and non-discriminatory treatment of TSOs, NEMOs, the Agency, regulatory authorities and market participants'.

(9) This document achieves the objective of ‘ensuring and enhancing the transparency and reliability of information’ as the HMMCP for SDAC have been publicly consulted both by all NEMOs as well as by the Agency. The final document will also be published.

(10) This document fulfils the objective of ‘contributing to the efficient long-term operation and development of the electricity transmission system and electricity sector in the Union’ as the HMMCP for SDAC have been set at levels that allow full provision of supply and demand orders in the SDAC and therefore SDAC results can contribute to the provision of efficient price signals for forward (long term) price formation that can enable efficient signals for investment in generation and demand side response.

(11) This document fulfils the objectives of ‘respecting the need for a fair and orderly market and fair and orderly price formation’ and ‘providing non-discriminatory access to cross-zonal capacity’ by harmonising the HMMCP across the bidding zones which participate in SDAC and among all NEMOs active within the given bidding zones.

(12) This document fulfils the objective of ‘creating a level playing field for NEMOs’ as the limits applied will always be identical for multiple NEMOs active within one individual bidding zone as well as single NEMOs active in more bidding zones.

TITLE 1

General provisions

Article 1

Subject matter and scope

The HMMCP shall be applied in all bidding zones which participate in SDAC pursuant to Article 41 of the CACM Regulation.

Article 1

Definitions and interpretation

1. Terms used in this document shall have the meaning of the definitions included in Article 2 of the CACM Regulation and the Commission Regulation (EU) No 543/2013 of 14 June 2013 on submission and publication of data in electricity markets and amending Annex I to Regulation (EC) No 714/2009 of the European Parliament and of the Council.

2. In addition, in this document the following terms shall apply:
   a) ‘Harmonised maximum clearing price for SDAC’ means the maximum clearing price value which is applied in all bidding zones which participate in SDAC; and
   b) ‘Harmonised minimum clearing price for SDAC’ means the minimum clearing price value which is applied in all bidding zones which participate in SDAC.

3. In this document, unless the context requires otherwise:
   c) the singular indicates the plural and vice versa;
   d) the table of contents, headings and examples are inserted for convenience only and do not affect the interpretation of this document; and
   e) any reference to legislation, regulations, directives, decisions, orders, instruments, codes or any other enactment shall include any modification, extension or re-enactment of it then in force.

TITLE 2

Maximum and minimum prices

Article 3

Harmonised maximum and minimum clearing prices for SDAC

1. The harmonised maximum clearing price for SDAC shall be +3000 EUR/MWh.

2. The harmonised minimum clearing price for SDAC shall be -500 EUR/MWh.

Article 4

Criteria and process for establishing and amending maximum price for SDAC

1. The harmonised maximum clearing price for SDAC in accordance with Article (0), shall be amended according to the following rules:
   a) the harmonised maximum clearing price for SDAC shall be increased by 1,000 EUR/MWh in the event that the clearing price exceeds a value of 60 percent of the harmonised maximum clearing price for SDAC in at least one market time unit in a day in an individual bidding zone or in multiple bidding zones;
   b) the increased harmonised maximum clearing price, set according to subparagraph (a), shall apply in all bidding zones which participate in SDAC from five weeks after the day in which the event referred to therein has taken place;
   c) notwithstanding subparagraph (b), for the further application of the amendment criterion defined in subparagraph (a), the increased harmonised maximum clearing price, set according to subparagraph (a), is used from the day following the one in which the event referred to therein has taken place; and
   d) the bidding zones referred to in subparagraph (b) are only those bidding zones with cleared buy and sell volumes and those part of the SDAC (excluding market time units where the given bidding zone(s) has been decoupled).

2. The NEMOs shall transparently announce and publish the amended harmonised maximum clearing price for SDAC at least four weeks before its implementation and application in SDAC.

3. The NEMOs shall, at least every two years, reassess the HMMCP, share this assessment with all market participants and consult it in relevant stakeholder forums organised in accordance with Article 11 of the CACM Regulation. A reassessment may also follow any amendment in accordance with paragraph (1), if the NEMOs deem it appropriate.

TITLE 3

Final provisions

Article 5

Timeline for implementation

The NEMOs shall implement the HMMCP for SDAC in all bidding zones participating in the SDAC immediately after the MCO function has been implemented in accordance with Article 7(3) of the CACM Regulation.

Article 6

Language disclaimer

The reference language for the HMMCP for SDAC shall be English. For the avoidance of doubt, where NEMOs need to translate this HMMCP for SDAC into the national language(s) of the relevant regulatory authority, in the event of inconsistencies between the English version submitted in accordance with Article 9(14) of the CACM Regulation and any version in another language, the relevant NEMO(s) shall be obliged to dispel any inconsistencies by providing a revised version of this HMMCP for SDAC to the relevant national regulatory authorities.

Annex I

Harmonised maximum and minimum clearing prices for single intraday coupling in accordance with Article 54(1) of Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (CACM Regulation)

14 November 2017

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Whereas

(1) This document sets the harmonised maximum and minimum clearing prices (’HMMCP’) in single intraday coupling (‘SIDC’) in accordance with Article 54(1) of the CACM Regulation.

(2) In accordance with Article 54(1) of the CACM Regulation, the HMMCP for SIDC shall take into account an estimation of the value of lost load (’VoLL’). The objective of this requirement is to ensure that the HMMCP for SIDC does not impose barriers on free price formation. This document sets the initial value of HMMCP for SIDC, which, in combination with the amendment rule of HMMCP for SIDC, is expected to achieve the same goal, i.e. to minimise the likelihood that the HMMCP for SIDC impose barriers on free price formation. The HMMCP for SIDC therefore implicitly take into account the VoLL, since an amendment rule ensures that the HMMCP for SDIC is always higher or equal to the HMMCP for SDAC, whereas the later is expected to gradually increase to a level, which represents the VoLL as determined by the market participants’ willingness to pay.

(3) The HMMCP for SIDC take into account the general objectives of capacity allocation and congestion management cooperation described in Article 3 of the CACM Regulation.

(4) This document fulfils the objective of ‘promoting effective competition in the generation, trading and supply of electricity’ as the HMMCP for SIDC have been set at levels that do not restrict effective competition in the generation, consumption, trading or supply in the organised wholesale market.

(5) This document fulfils the objective of ‘ensuring operational security’ by harmonising HMMCP for SIDC as well as removing barriers for free price formation. This promotes flexibility and thereby contributes to the operational security, as well as security of supply.

(6) This document fulfils the objective of ‘optimising the calculation and allocation of cross-zonal capacity’, and in parts also the objective of ‘optimal use of the transmission infrastructure’, by removing the barriers for free price formation which effectively optimises the allocation of cross-zonal capacities and the use of transmission infrastructure.

(7) This document fulfils, or rather is deemed to have no negative impact on, the objective of "ensuring fair and non-discriminatory treatment of TSOs, NEMOs, the Agency, regulatory authorities and market participants’.

(8) This document achieves the objective of ‘ensuring and enhancing the transparency and reliability of information’ as the HMMCP for SIDC have been publicly consulted both by all NEMOs as well as by the Agency. The final document will also be published.

(9) This document fulfils the objective of ‘contributing to the efficient long-term operation and development of the electricity transmission system and electricity sector in the

Union' as the HMMCP for SIDC have been set at levels that allow full provision of supply and demand orders in to the SIDC markets and therefore SIDC results can contribute to provision of efficient price signals for forward (long term) price formation that can enable efficient signals for investment in generation and demand-side response.

(10) This document fulfils the objectives of 'respecting the need for a fair and orderly market and fair and orderly price formation' and 'providing non-discriminatory access to cross-zonal capacity' by harmonising the HMMCP across the bidding zones which participate in SIDC and among all NEMOs active within the given bidding zones.

(11) This document fulfils the objective of 'creating a level playing field for NEMOs' as the limits applied will always be identical for multiple NEMOs active within one individual bidding zone as well as single NEMOs active in more bidding zones.

TITLE 1

General provision

Article 1

Subject matter and scope

The HMMCP shall be applied in all bidding zones which participate in SIDC in accordance with Article 54(1) of the CACM Regulation.

Article 2

Definitions and interpretation

1. Terms used in this document shall have the meaning of the definitions included in Article 2 of the CACM Regulation.

2. In addition, in this document the following terms shall apply:
   a) 'Harmonised maximum clearing price for SIDC' means the maximum clearing price value, which is applied in all bidding zones which participate in SIDC; and
   b) 'Harmonised minimum clearing price for SIDC' means the minimum clearing price value, which is applied in all bidding zones which participate in SIDC.

3. In this document, unless the context requires otherwise:
   c) the singular indicates the plural and vice versa;
   d) the table of contents, headings and examples are inserted for convenience only and do not affect the interpretation of this document; and
   e) any reference to legislation, regulations, directives, decisions, orders, instruments, codes or any other enactment shall include any modification, extension or re-enactment of it then in force.

TITLE 2

Maximum and minimum prices

Article 3

Harmonised maximum and minimum clearing prices for SIDC

1. The harmonised maximum clearing price for SIDC shall be +9999 EUR/MWh.

2. The harmonised minimum clearing price for SIDC shall be -9999 EUR/MWh.

Article 4

Criteria and process for establishing and amending maximum price for SIDC

1. The harmonised maximum clearing price for SIDC in accordance with Article 3(1) shall be amended in the event that harmonised maximum clearing price for SDAC is increased above the harmonised maximum clearing price for SIDC pursuant to Article 4 of the *Harmonised maximum and minimum clearing prices for single day-ahead coupling in accordance with Article 41(1) of Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management*. In such a case, the harmonised maximum clearing price for SIDC shall also increase to be equal to the harmonised maximum clearing price for SDAC. Any such change shall be implemented and applied at the same time that the harmonised maximum clearing price for SDAC is applied.

2. The NEMOs shall transparently announce and publish the amended harmonised maximum clearing price for SIDC at least four weeks before its implementation and application in SIDC.

3. The NEMOs shall, at least every two years, reassess the HMMCP, share this assessment with all market participants and consult it in relevant stakeholder forums organised in accordance with Article 11 of the CACM Regulation. A reassessment may also follow any amendment in accordance with paragraph (**Error! Reference source not found.**), if the NEMOs deem it appropriate.

TITLE 3

Final provisions

Article 5

Timeline for implementation

The NEMOs shall implement the HMMCP for SIDC in all bidding zones participating in the SIDC immediately after the MCO function has been implemented in accordance with Article 7(3) of the CACM Regulation.

Article 6

Language disclaimer

The reference language for the HMMCP for SDAC shall be English. For the avoidance of doubt, where NEMOs need to translate this HMMCP for SDAC into the national language(s) of the relevant regulatory authority, in the event of inconsistencies between the English version submitted in accordance with Article 9(14) of the CACM Regulation and any version in another language, the relevant NEMO(s) shall be obliged to dispel any inconsistencies by providing a revised version of this HMMCP for SDAC to the relevant national regulatory authorities.

All NEMO proposal for the MCO Plan

13th April 2017

This document was jointly prepared and approved by:

BSP Regional Energy Exchange LLC, **Croatian Power Exchange Ltd.**, **EirGrid plc**, **EPEX SPOT SE**, **EPEX SPOT Belgium SA, EXAA Abwicklungsstelle für Energieprodukte AG**, **Gestore dei Mercati Energetici S.p.A., HUPX Hungarian Power Exchange Company Limited by Shares, Independent Bulgarian Energy Exchange EAD**, **Operator of Electricity Market S.A.**, **Nord Pool AS, OKTE a.s., OMI - Polo Español S.A. (OMIE), Operatorul Pieţei de Energie Electrică şi de Gaze Naturale "OPCOM" SA, OTE A.S.**, **SONI Limited** and **Towarowa Giełda Energii S.A.**

Contents

1 INTRODUCTION

Whereas:

1. This document is a common proposal developed by all Nominated Electricity Market Operators (the "**NEMOs**") for a plan that sets out how NEMOs will jointly set up and perform the Market Coupling Operator (MCO) Functions (the "**MCO Plan**") pursuant to article 7(2) of Commission Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management (the "**CACM Regulation**").

2. The MCO Functions comprise developing and maintaining the algorithms, systems and procedures for single day-ahead and intraday coupling, processing input data on cross-zonal capacity and allocation constraints provided by coordinated capacity calculators, operating the price coupling and continuous trading algorithms and validating and sending single day-ahead and intraday coupling results to NEMOs (the "**MCO Functions**").

3. This MCO Plan takes into account the general principles and goals set in the CACM Regulation. In particular, this MCO Plan includes an explanation of the necessary draft agreements between NEMOs and with third parties; a proposed timescale for implementation, which is not longer than 12 months; a description of the expected impact of the MCO Plan on the objectives of the CACM Regulation; and, a description of the expected impact of the terms and conditions or methodologies on the establishment and performance of the MCO Functions.

4. Prior to the entry into force of the CACM Regulation, power exchanges initiated several voluntary regional projects to develop, implement and operate day-ahead and intraday market coupling solutions. These regional projects promoted the completion and efficient functioning of the internal market in electricity. For the efficient implementation of the MCO Plan we propose to build single day-ahead and intraday coupling on existing solutions developed as part of these voluntary projects.

5. This MCO Plan proposes a governance structure for NEMOs to jointly set up and perform the DA MCO Function and the ID MCO Function which builds on solutions developed as part of these voluntary projects. The governance structure proposed in this MCO Plan includes the following contracts: one "All NEMO Cooperation Agreement" (the "**ANCA**"), two "NEMO Operational Agreements" (one for the DA and one for the ID), plus a set of contracts between NEMOs and third party service providers needed for the delivery of the MCO Functions.

6. The ANCA will be developed based on the principles set out in this MCO Plan and will be open to all NEMOs. In particular, the MCO Plan contains provisions to make necessary the signature of the ANCA by all designated NEMOs wishing to make use of the DA or ID MCO Function. As NEMOs are incorporated legal entities, each governed by the law of their country of incorporation, it is necessary that any agreement to co-operate to meet the requirements of the CACM Regulation is enshrined not only in the MCO Plan, but also in a binding contract. It is envisaged that such contracts will set out in detail the rights and responsibilities of each NEMO to the others with respect to the common performance of the MCO Functions prescribed in articles 7 and 9(6) of the

CACM Regulation. Such a contract will also be key in ensuring that the cooperation between NEMOs is strictly limited to what is necessary to perform the MCO Functions, as required by article 7(4) of the CACM Regulation.

7. The proposed operational governance for the DA MCO Function and the ID MCO Function will be based on the principles set out in this MCO Plan and by adapting existing solutions developed as part of the voluntary projects.

8. This MCO Plan sets the basis for the NEMOs to enter into the contracts with the DA and ID service providers already in use, after the approval of this MCO Plan.

9. In accordance with the CACM Regulation NEMOs have included the necessary draft agreements. Where these agreements are still in the process of being finalised, the content provided is based on the most accurate information available at the time of submission of this MCO Plan to NRAs and may change.

10. The NEMO arrangements explained in the MCO Plan that are necessary for the design, implementation and operation of the MCO Functions have to be complemented by additional "all NEMO - all TSO" agreements, as well as national and regional "NEMO and TSO" agreements, which are necessary for pre-coupling and post-coupling activities. These additional agreements are necessary for the operation of single day-ahead and intraday market coupling and are outside the scope of the MCO Plan.

11. The reference language for the MCO Plan shall be English. For the avoidance of doubt, where NEMOs need to translate this MCO Plan into the national language(s) of the relevant NRA, in the event of inconsistencies between the English version submitted in accordance with article 9 (14) of the CACM Regulation and any version in another language, the relevant NEMO(s) shall be obliged to dispel any inconsistencies by providing a revised version of this MCO Plan to their relevant national regulatory authorities.

1.1 Assessment against the objectives listed in article 3 of the CACM Regulation

1.1.1 General remarks

1. The expected impact of the MCO Plan on the objectives of the CACM Regulation is outlined below. This assessment focus on the following objectives (the "CACM Objectives"):
   a) Promoting effective competition in the generation, trading and supply of electricity;
   b) Ensuring optimal use of the transmission infrastructure;
   c) Ensuring operational security;
   d) Optimising the calculation and allocation of cross-zonal capacity;
   e) Ensuring fair and non-discriminatory treatment of TSOs, NEMOs, the Agency, regulatory authorities and market participants;
   f) Ensuring and enhancing the transparency and reliability of information;
   g) Contributing to the efficient long-term operation and development of the electricity transmission system and electricity sector in the Union;

h) Respecting the need for a fair and orderly market and fair and orderly price formation;
i) Creating a level playing field for NEMOs;
j) Providing non-discriminatory access to cross-zonal capacity.

2. The proposed DA MCO Function and ID MCO Function build on contractual arrangements, processes and systems that have already been established in existing solutions. This should help to ensure that the proposed solutions meet the CACM Objectives.

3. A number of operational features common to the proposed DA and ID MCO functions contribute to the achievement of the CACM Objectives. These features are:

    a. The use of one single algorithm for the DA timeframe, and of one single algorithm for the ID timeframe, each designed to achieve optimal cross zonal capacity allocation and maximise welfare;
    b. The use of one single set of input data for the whole coupled area for each timeframe;
    c. The production of one single set of results for the whole coupled area for each timeframe;
    d. The requirement that each NEMO prepares and collects input data to the algorithm according to local Regulations and/or market contracts in a common format;
    e. The requirement that the respective input data provider (TSO or Market Participant) is responsible for the input data content according to local regulations and/or market contracts;
    f. The requirement that MCO results for each timeframe are repeatable and auditable.

4. In addition, some operational features of the DA MCO function contribute to the achievement of the CACM Objectives in the DA timeframe. These are listed in Section 6.1.1 and are:

    a. The fact that the complete input data file is received by the Coordinator/Backup Coordinator and all Operators in an anonymised manner. This guarantees the transparency of the process since all parties guarantee that the same input data is used in the DA MCO results calculation process;
    b. The right of each NEMO, in exercising the Operator function to compute the results in parallel to the Coordinator and Backup Coordinator;
    c. The obligation placed on each NEMO (directly or together with its Servicing NEMO) to validate its results and be responsible (in a decentralised manner) for its results;
    d. The fact that, once results are finally accepted by all NEMOs they are absolutely firm, and there is no possibility for any NEMOs to contest the accepted results or to claim against the other NEMOs, including the Coordinator.

5. The features listed in Section 7.1.1, paragraphs 2 to 8, ensure the achievement of the CACM Objectives for the ID MCO Function.

6. Finally, the fact that development and implementation of the existing solutions has been undertaken together with TSOs will help to ensure operational security, helps ensure that the MCO Plan meets requirements b, c, d, e, h, i and j of article 3 of the CACM Regulation.

7. In Sections 1.1.2 to 1.1.10 we provide additional information specific to each objective.

1.1.2 Assessment of objective a) Promoting effective competition in the generation, trading and supply of electricity

1. In addition to the assessment made in Section 1.1.1, the architecture, principles and procedure listed in Sections 6.1.2, 6.1.3 and 6.1.4 for the DA timeframe, and in Sections 7.1.1.2, 7.1.1.3, 7.2, 7.2.1 and 7.2.2 for the ID timeframe are designed to promote, among other objectives, effective competition in the generation, trading and supply of electricity.

1.1.3 Assessment of objectives b) Ensuring optimal use of the transmission infrastructure; and c) Ensuring operational security

1. The operational features mentioned in Sections 1.1. and 1.1.1 are designed to ensure the achievement of these objectives.

1.1.4 Assessment of objective d) Optimising the calculation and allocation of cross-zonal capacity

1. Optimising the calculation and allocation of the cross-zonal capacity depends mostly on the features of the DA and ID algorithms – which are described in a separate methodology.

2. Insofar as the MCO Plan is concerned, the operational features mentioned in Sections 1.1. and 1.1.1, in conjunction with the specific features of the algorithm, aim to ensure an optimal calculation and allocation of the cross-zonal capacity.

1.1.5 Assessment of objective e) Ensuring fair and non-discriminatory treatment of TSOs, NEMOs, the Agency, regulatory authorities and market participants

1. This MCO Plan does not in any way restrict a NEMO's responsibility to ensure fair and non-discriminatory treatment of TSOs, NEMOs, the Agency, regulatory authorities and market participants, and create a level playing field for NEMOs in accordance with the CACM Regulation, in line with the principles included in this MCO Plan and the other relevant methodologies or terms and conditions listed in article 9 of the CACM Regulation. The competent regulatory authorities assess and approve such methodologies and may request changes. They have the right to access any underlying contracts and documentation upon request.
2. All NEMOs shall ensure fair and non-discriminatory treatment by, amongst others, performing the following joint actions:
   a. Submitting information and necessary reports to the Agency, ENTSO-E, regulatory authorities and the European Commission as required under the CACM Regulation TSOs as detailed in Section 4.2(5), point e.
   b. Providing information to ENTSO-E, if it has been requested jointly by the Agency and ENTSO-E as detailed in Section 4.2(5), point f.
   c. Providing an annual report to stakeholders on progress with the implementation and the operational performance of the DA MCO Function and the ID MCO Function.

3. The governance structure proposed in the MCO Plan and the associated procedures outlined in Sections 6.1 to 6.2 for the DA timeframe and Sections 7.1 to 7.2 for the ID timeframe, are designed to ensure fair and equal treatment of all participating NEMOs, TSOs and market participants according to article 3(c) of the CACM Regulation.

1.1.6 Assessment of objective f) Ensuring and enhancing the transparency and reliability of information

1. This MCO Plan shall ensure and enhance the transparency and reliability of information in three main ways:

    a. The reporting duties outlined in Section 1.1.5 above;
    b. The governance structure outlined in Section 1.1.5 and
    c. Specific operational features listed in Sections 6.1.2, 6.1.3 and 6.1.4 for the DA timeframe, and in Sections 7.1.1.2, 7.1.1.3, 7.2, 7.2.1 and 7.2.2 for the ID timeframe.

1.1.7 Assessment of objective g) contributing to the efficient long-term operation and development of the electricity transmission system and electricity sector in the Union

1. This MCO Plan shall ensure the achievement of this objective by:

    a. Building on contractual arrangements, processes and systems that have already been established in existing solutions.
    b. Establishing a sound governance structure, open to scrutiny by the competent regulatory authorities and stakeholders, and underpinned by binding legal contracts between the NEMOs
    c. Establishing robust operational procedures, including, where appropriate, in cooperation with TSOs.

1.1.8 Assessment of objective h) Respecting the need for a fair and orderly price formation

1. For the DA timeframe, the procedures to ensure a fair and orderly price formation are outlined in Section 6.1.3 on Operational sequence of events in a Market Coupling session and Section 6.1.4 on Validation of the Day Ahead Market Coupling session results.

2. For the ID timeframe, such procedures are listed in Section 7.1.1.2 on Cross-border matching during the continuous trading period and Section 7.1.1.3 on Validation of the Intraday Market Coupling results.

1.1.9 Assessment of objective i) Creating a level playing field for NEMOs

1. This MCO Plan foresees a contractual structure (outlined in Section 3.1) that is designed to create a level playing field among NEMOs, insofar as all aspects related to the joint performance of the MCO Function are concerned.

2. Key elements that will ensure that the joint performance of the MCO Functions creates a level playing field for NEMOs include:

    a. The requirement on all NEMOs to sign up to the ANCA agreement, which sets out the rules for the cooperation between NEMOs, and sets up an All NEMO Committee as its main body to facilite all NEMOs decision-making process. The ANCA must be agreed unanimously by all NEMOs and is specifically designed to be open to the adherence of new parties.
    b. The requirement that all NEMOs designated for SDAC and SIDC shall sign the DA and to the ID Operational Agreement respectively, which set out the rules for the cooperation of NEMOs in accordance with article 7 of the CACM Regulation. These agreements shall be open to the adherence of new parties.

c. The areas where cooperation will be regulated by the NEMO DA Operational Agreement are listed in Section 5.1.2(4), whereas the areas where cooperation will be regulated by the NEMO ID Operational Agreement are listed in Section 5.2.2(13). Further safeguards are included:

    i. If no consensus is reached among the concerned NEMOs on a decision taken in execution of the scope of the ID or DA Operational Agreements, the decision is escalated to the All NEMO Committee.
    ii. To ensure equal participation of all NEMOs, the Agreements shall also be signed by NEMOs which are not yet Operational NEMOs.

3. The separation of the processes and bodies for operational decisions related to the MCO Function (taken by NEMOs by consensus) from high level decisions stemming from the CACM requirements (taken by qualified majority voting).
4. The obligation on NEMOs that the MCO Function assets (i.e. rules, procedures and specifications) shall meet the requirements of the CACM Regulation and the approved terms and conditions or methodologies.

1.1.10 Assessment of objective j) Providing non-discriminatory access to cross-zonal capacity.

1. In addition to the assessment made in Section 1.1, the architecture, principles and procedure listed in Sections 6.1.2, 6.1.3 and 6.1.4 for the DA timeframe, and in Sections 7.1.1.2, 7.1.1.3, 7.2., 7.2.1 and 7.2.3 for the ID timeframe are designed to provide non-discriminatory access to cross-zonal capacity.

2 DEFINITIONS

In this MCO Plan, the same definitions used in Commission Regulation EU 2015/1222 are applied, plus the following.

[1]. **APCA:** All Party Cooperation Agreement between NEMOs and TSOs, to be extended from the implementation timescale for the ID MCO Function.

[2]. **Backup Coordinator**: means a DA NEMO which in addition to performing the task as an Operator, is prepared, if necessary, to take over the Coordinator role at any moment.

[3]. **Capacity Management Module (CMM): as defined in article 2(11) of the CACM Regulation**

[4]. **Coordinator**: means a DA NEMO which, in addition to performing the tasks of an Operator, is responsible for coordinating the operation of the DA MCO Function.

[5]. **DA Market Coupling Operator (MCO) Function:** means the task of matching orders from the day-ahead markets for different bidding zones and simultaneously allocating cross-zonal capacities, as defined in article 2(30) of the CACM Regulation.

[6]. **Global Products:** means all products set up in the Intraday Solution and eligible to be matched in the Intraday Solution.

[7]. **ID Market Coupling Operator (MCO) Function:** means the task of matching orders from the intra-day markets for different bidding zones and simultaneously allocating cross-zonal capacities, as defined in article 2(30) of the CACM Regulation.

[8]. **LIP**: local implementation project, which is national or regional in scope, whose readiness is a pre-condition to join Single Intraday Coupling operations.

[9]. **Local Products:** means all products not set up in the Intraday Solution and not eligible to be matched in the Intraday Solution.

[10]. **Nominated Electricity Market Operator (NEMO):** as defined in article 2(23) of the CACM Regulation

[11]. **Operational NEMO**: means

a. In DA: a DA NEMO whose orders are being matched by the DA MCO Function;

b. In ID: an ID NEMO whose orders are being matched by the ID MCO Function.

[12]. **Operator:** means a DA NEMO performing the DA MCO Functions during the Market Coupling Phase, which provides the Coordinator information needed for the calculation of the market coupling results, participates in the actions convened by the Coordinator, complies with commonly agreed decisions and accepts or rejects the market coupling results for its own results (plus those of any NEMO that it services).

[13]. **DA MCO Function Assets**: means the systems, procedures, algorithm and service provider contracts used for the DA MCO Function.

[14]. **DA MCO Function Assets Co-Owner**: means a DA NEMO that is a co-owner of the DA MCO Function Assets.

[15]. **DA MCO Function Assets Co-Owners**: means all DA NEMOs that have joint ownership of the DA MCO Function Assets.

[16]. **DA MCO Function Assets Licensees**: means all DA NEMOs that have a license providing them with the right to use the DA MCO Function Assets in its own name as Coordinator/Backup coordinator/Operator solely to perform the DA MCO Functions for the purpose of Single Day Ahead Coupling.

[17]. **PMB**: means the Matcher and Broker (a part of DA MCO Function Assets).

[18]. **Serviced NEMO**: means a NEMO which has delegated some of its MCO tasks to another NEMO, according to a bilateral service provision agreement.

[19]. **Servicing NEMO:** means a NEMO, who shall be a DA MCO Function Asset Co-Owner, acting in the name and for the account of a Serviced NEMO in the delegated tasks.

[20]. **Shared Order Book (SOB):** as defined in article 2(24) of the CACM Regulation.

[21]. **Shipping Module (SM):** computes the scheduled exchanges for TSOs and central counter parties to ship and settle cross-zonal and cross-delivery area and cross- central counter party trades, where relevant.

[22]. **Single Day Ahead Coupling (SDAC):** as defined in article 2(26) of the CACM Regulation.

[23]. **Single Intraday Coupling (SIDC):** as defined in article 2(27) of the CACM Regulation.

[24]. **Intraday Solution:** means the solution (system, procedures, contracts, etc.) to be implemented by the PXs and TSOs for implicit cross zonal continuous intraday capacity allocation and also explicit allocation within the scope of the Single Intraday Coupling according to the principles set forth in the CACM Regulation.

[25]. **Intraday System Supplier**: means the entity providing the Intraday market coupling services according to the respective agreements signed with NEMOs.

[26]. **Intraday System:** means the software and ICT applications (incl. hardware) to be used for the operation of the Intraday Solution to interact with amongst others the Local Trading Systems (LTS) of each PX, the TSOs systems and the explicit capacity allocation participants in borders where this possibility exists.

3 GENERAL PRINCIPLES FOR THE NEMO COOPERATION

1. The cooperation of the NEMOs for the implementation and delivery of the MCO Functions under articles 7(2) and 7(3) of the CACM Regulation and the definition of the relevant terms and conditions or methodologies under article 9(6) of the CACM Regulation will be managed through the following set of contracts[1]:
    a. One "*ALL-NEMO Cooperation Agreement*" (ANCA), signed by all designated NEMOs, which will set out the rules for the cooperation of the NEMOs in accordance with article 9 of the CACM Regulation;
    b. Two *"NEMO Operational Agreements*" (one for the DA and one for the ID), signed respectively by all NEMOs designated for SDAC and SIDC, which will set out the rules for the cooperation of NEMOs in accordance with article 7 of the CACM Regulation;
    c. A set of contracts between NEMOs and third party service providers, including the DA MCO Function Co-owners, needed for the delivery of the MCO Functions.

2. Contracts provided under Section 3(1) of this MCO Plan shall:
    a. Benefit from existing contractual arrangements for the development and operation of DA and ID market coupling;
    b. Be extended via an adherence process to NEMOs that are not yet signatories;
    c. Reflect the fact that, while all NEMOs will have to sign the ANCA, not all NEMOs are Operational NEMOs in the DA and/or ID timeframes;
    d. Support and safeguard the efficient management of the overall process by clearly distinguishing the responsibilities for operational decisions, from higher level decisions;
    e. Set obligations for NEMOs to cooperate for the implementation and delivery of the MCO Functions.

3. A NEMO designated to perform tasks related to SDAC or SIDC shall enter into the relevant contracts described in the MCO Plan for the implementation and delivery of the MCO Functions which are necessary for the common, coordinated and compliant operation of SDAC and SIDC.

4. The cooperation between NEMOs to implement the MCO Plan shall ensure that the joint performance of the MCO Functions shall be based on the principle of non-discrimination and ensure that no NEMO can benefit from unjustified economic advantages arising from its role in the MCO Functions in accordance with article 7(4) of the CACM Regulation.

5. In accordance with article 7(4) of the CACM Regulation the cooperation among NEMOs shall be strictly limited to what is necessary for the joint delivery of the DA MCO Function and ID MCO Function, to enable the efficient and secure design, implementation and operation of single DA and ID coupling. Therefore, apart from the provisions which are strictly necessary to coordinate their matching into a price coupling mechanism, each Party will keep its full independency and self-determination for its own business.

[1] Contracts among all NEMOs and all TSOs as well as national and regional agreements needed to set out the pre- and post-coupling phase/processes of the MCO fucntions in DA and ID are outside the scope of this MCO Plan.

6. NEMOs shall be able to perform DA and/or ID coupling operations only if further agreements between NEMOs and TSOs for the availability of cross-border capacity and the provision of the cross-border shipping are set up. Such agreements are beyond the scope of this MCO Plan.

7. Under the contractual structure proposed in Section 3(1) of this MCO Plan, the following tasks related separately to DA and/or ID shall be managed by all NEMOs designated for DA and/or ID respectively:
    a. Approval of budget, high-level investments and planning for further development of the MCO Functions;
    b. Resolution of any issues escalated from the Operational NEMOs;
    c. Submission of external reporting and representation;
    d. Management of stakeholder consultations.

    Any decision needed to fulfil tasks performed by NEMOs designated for DA and/or ID respectively shall be taken by the All NEMOs Committee as described in Section 4 of this MCO Plan.

8. Under the contractual structure proposed in Section 3(1) of this MCO Plan, the following tasks shall be managed by the Operational NEMOs that have signed the relevant NEMO Operational Agreement as referred to in Section 3(1)(b) of this MCO Plan:
    a. Approval of relevant[2] rules and procedures for the operation of single DA and/or ID market coupling respectively;
    b. Preparation of proposals for investment, budget and planning for further development of MCO Function as referred to in Section 3(7)(a) of this MCO Plan;
    c. Management of the change control process and its impact assessment and overseeing the implementation of changes.

    Any decision needed to fulfil the tasks mentioned above shall be taken unanimously. The decision shall be escalated to the All NEMO Committee if no consensus can be reached among Operational NEMOs.

9. Under the contractual structure proposed in Section 3(1) of this MCO Plan, the following tasks shall be managed by all NEMOs who are Coordinator, Backup Coordinator or Operators in DA or by Operational NEMOs in ID:
    a. Maintenance and day to day operation of the MCO Function according to the rules and procedures agreed by the Operational NEMOs;
    b. Real time application of the procedures in MCO Function operation;
    c. Analysis of incidents incurred in the MCO Function operation;
    d. Provide necessary support for analysis and testing related to further development of the MCO Function for any decision by the Operational NEMOs.

    Any actions needed in order to fulfil the above-mentioned tasks shall be taken according to the agreed procedures.

[2] Does not refer to the methodologies listed in article 9(6) of the CACM Regulaton.

10. In accordance with the article 81 of the CACM Regulation a NEMO may delegate operational activities associated with the performance of the MCO Function to a Servicing NEMO. In such case:
    a. The delegating NEMO (hereinafter Serviced NEMO) shall remain responsible for the performance of the MCO Function.
    b. The delegation of operational activities under Section 3(9) from one NEMO to another will be managed through bilateral contracts entered into between Serviced NEMO and Servicing NEMO, that shall be compliant with the rules set out in the NEMO Operational Agreements and the CACM Regulation.
    c. Without prejudice to the rights under Sections 3(7) and 3(8) of this MCO Plan, the operational decision making under Section 3(9) is delegated by the Serviced NEMO to the Servicing NEMO.

11. NEMOs may apply different governance rules in DA and/or ID while complying with the general principles of non-discrimination and maintaining the level-playing field set by the CACM Regulation and by this MCO Plan.

12. Paying due regard to the objectives of CACM as well as to the applicable European and national legal provisions, MCO Function system and service providers shall be selected consistently with the principles of equal treatment, objectiveness of the selection criteria, transparency, economic efficiency, efficacy and timeliness.

4 ALL NEMO COMMITTEE

4.1 All NEMO Cooperation Agreement (ANCA)

1. To be able to participate in the single day-ahead and intraday coupling under CACM all NEMOs shall become a party to the ANCA. An entity designated as a NEMO in at least one bidding zone shall be entitled to become party to the ANCA and join the All NEMO Committee. An adhering NEMO may request an amendment of the ANCA.

2. The ANCA shall:
    a. Set up the All NEMO Committee as further described in Section 4.2 of this MCO Plan;
    b. Establish an escalation procedure to manage the cases of the refusal of any NEMO to sign or approve a revised version of the DA and/or ID NEMO Operational Agreements;
    c. Establish decision making rules for the All NEMO Committee based on article 9 of the CACM Regulation;
    d. Provide an adherence process;
    e. Be developed based on the principles set out in this MCO Plan and approved by All NEMOs unanimously.

3. An entity designated as a NEMO in a non-EU country shall be entitled to become party to the ANCA and join the All NEMO Committee if it meets the requirements of article 1(4) of the CACM regulation.

4. An entity designated as a NEMO in a non-EU country participating in single DA and/or ID coupling shall have rights and responsibilities equivalent to the rights and responsibilities of a NEMO designated in a Member State, in order to allow a smooth functioning of the single day-ahead and intraday coupling systems implemented at European Union level, and a level-playing field for all stakeholders.

4.2 All NEMO Committee: roles and responsibilities

1. The All NEMO Committee shall facilitate cooperation between NEMOs for all common European tasks necessary for the efficient and secure design, implementation and operation of single day-ahead and intraday coupling.

2. To fulfil this role, the All NEMO Committee shall be formed by the appointed representatives of each NEMO. Organisation and representation of the NEMOs shall be established in the internal rules of All NEMO Committee as set out in the ANCA. The All NEMO Committee may create or dissolve working groups or task forces. In such event the All NEMO Committee shall determine the purpose, composition, organisational and governance arrangements for such task force or working group.

3. The All NEMO Committee shall publish approved summary minutes of its meetings on a designated website.

4. The European Commission and the Agency shall be invited to participate in All NEMO Committee meetings as observers.

5. The All NEMO Committee shall facilitate the necessary cooperation between NEMOs for joint European tasks required by the CACM Regulation or the MCO Plan including:
   a. All tasks associated with the development, consultation, approval, submission, implementation, publication and future amendment of the MCO Plan required by article 7 paragraph 3 of the CACM Regulation, and other terms and conditions or methodologies required by article 9 paragraph 6 of the CACM Regulation.
   b. Necessary cooperation between NEMOs and TSOs, where TSOs are responsible for submitting or amending proposals for terms and conditions or methodologies specified in article 9 paragraph 6 of the CACM Regulation.
   c. Determining changes to the governance framework, including the structure of committees set up under the NEMO DA Operational Agreement and NEMO ID Operational Agreement.
   d. Submitting information and necessary reports to the Agency, ENTSO-E, regulatory authorities and the European Commission as required under the CACM Regulation. In particular, the All NEMO Committee shall report to:
      i. The Agency on NEMO progress in establishing and performing the DA and ID MCO Functions in accordance with article 7 paragraph 5 of the CACM Regulation.
      ii. The Agency, in cooperation with TSOs, to provide a review of the operation of the price coupling algorithm and continuous trading matching algorithm in accordance with article 37 paragraph 6 of the CACM Regulation.
   e. Providing information to ENTSO-E, if it has been requested jointly by the Agency and ENTSO-E, for the purpose of implementation monitoring, in accordance with article 82 paragraph 6 of the CACM Regulation.
   f. Ensuring that the MCO Function assets (i.e. rules, procedures and specifications) meet the requirements of the CACM Regulation and the approved terms and conditions or methodologies.
   g. Setting the criteria for decisions relating to change of the assets or providers.
   h. Establishing a process for the All NEMO Committee to act as an escalation body for the committees under the NEMO DA Operational Agreement and the NEMO ID Operational Agreement, where they have not been able to reach agreement on the basis of unanimity. In such cases the DA Operational Committee or the ID Operational Committee shall provide a written report to the All NEMO Committee. Disputes regarding the execution of contracts shall not be subject to escalation to the All NEMO Committee but shall be governed by the relevant provisions in each contract.
   i. Providing an annual report to stakeholders on progress with the implementation and the operational performance of the DA MCO Function and the ID MCO Function.
   j. Approving the proposed budget related to All NEMO responsibilities as described in this Section of the MCO Plan. A process shall be established to update this budget over the course of the relevant year.

k. Facilitating NEMOs participation in the establishment and performance of joint TSO and NEMO organisation of the day-to-day management of the single day-ahead coupling and single intraday coupling in accordance with article 10 of the CACM Regulation.
l. Acting as a joint point of contact for regulatory authorities, the Agency, ENTSO-E and the European Commission in relation to the design, implementation, operation and amendment of the DA and ID MCO Functions. This includes any process launched by the Commission to consult NEMOs on amendments to the CACM Regulation.
m. External communication related to the DA MCO Function and ID MCO Function.

6. The decision-making rules of the All NEMO Committee shall be based on the requirements of article 9 paragraph 2 of the CACM Regulation.

7. For the avoidance of doubt, DA-related decisions shall be taken only by NEMOs designated for day-ahead, and similarly ID-related decisions shall be taken only by NEMOs designated for intraday.

5 IMPLEMENTATION TIMELINE

5.1 Implementation of the DA MCO Function

1. The MCO Plan sets out the necessary tasks for all NEMOs to jointly set up and perform the DA MCO Function. The tasks include the adoption of PCR as the starting point for the DA MCO Function (as described in Section 5.1.1), technical milestones (as described in Section 5.1.3), and contractual milestones to implement the necessary contracts and governance arrangements for the operation of the DA MCO Function (as described in Section 5.1.2).

2. In accordance with the CACM Regulation the MCO Plan includes a detailed description of the milestones and a proposed timescale for the implementation of the DA MCO Function, which shall not be longer than 12 months. In accordance with article 7(5) of the CACM Regulation the All NEMO Committee shall report to Agency on progress in meeting the technical and contractual milestones.

3. The MCO Plan shall be considered implemented when the technical and contractual milestones set out in this Section of the MCO Plan have been completed, and the DA MCO function is available for any NEMO to use.

4. In order for NEMOs to use the DA MCO Function they must in addition meet the necessary technical and contractual preconditions which are explained in Section 5.1.4.

5. NEMOs plan that the DA MCO Function implementation, and all technical and contractual milestones necessary for NEMOs to deliver the DA MCO Function, is targeted to be completed by April 2018, and shall in any case not be longer than 12 months from the date of approval of the MCO Plan.

6. The implementation of pre and post coupling activities necessary for the DA MCO Function to be used for capacity allocation on a bidding zone border are outside the scope of the MCO Plan.

5.1.1 Adoption of the PCR Solution as the DA MCO Function

1. The delivery of the DA MCO Function, in accordance with article 36(4) of the CACM Regulation, shall be based on the PCR solution (IT assets and relevant procedures), which is the existing solution used for day-ahead coupling developed prior to the entry into force of the CACM Regulation.

2. The steps required for the DA MCO Function becoming operational in a Member State include:
    a. Contractual readiness (Section 5.1.2),
    b. Technical readiness (Section 5.1.3)
    c. Local implementation readiness (Section 5.1.4).

5.1.2 Contractual milestones for implementation of the DA MCO Function

1. The NEMO cooperation for delivering the DA MCO Function shall be based on the following contractual framework:

a. the All NEMO Cooperation Agreement ("ANCA")
b. The NEMO DA Operational Agreement, which will govern the cooperation between NEMOs and the relationship with the DA MCO Function service provider, the DA MCO Function Asset Co-owners.

2. Upon entry into force of the ANCA, the general governance framework shall be set by the ANCA. Specifically, under the ANCA, decisions by signatories to the NEMO DA Operational Agreement, related to the implementation and operation of the SDAC, will be taken based on unanimity, and shall be escalated to the All NEMO Committee when unanimity cannot be reached.

3. NEMOs plan that all NEMOs designated to perform SDAC shall adhere to the ANCA by November 2017.

4. To be able to participate in SDAC, all NEMOs designated to perform SDAC shall become a party to the NEMO DA Operational Agreement. The NEMO DA Operational Agreement shall set out the NEMOs cooperation for the performance of the DA MCO Function provided under Article 7 of the CACM Regulation. This contract will govern the NEMOs cooperation in respect of:
   a. The daily management of the DA coupling operations;
   b. The different operational options of the NEMOs (operating NEMOs vs serviced NEMOs) and the technical requirements to satisfy in order to be an operator and to ensure safe and reliable operations;
   c. The contractual management of MC operational liabilities and results acceptance;
   d. The rules for participation in the bodies established under the contract, including for NEMOs not yet in operation;
   e. The management of cost reporting;
   f. The rules for the selection of the DA MCO Function service provider;

5. NEMOs plan that all NEMOs designated to perform SDAC shall enter into the NEMO DA Operational Agreement by February 2018, and in any case not longer than 12 month MCO Plan implementation period, to enter into force at go-live.

5.1.3 Technical milestones for implementation of the DA MCO Function

1. The following technical and operational developments are necessary for the selected DA MCO Function to meet the CACM requirements (for example, arising from new products or algorithm requirements).

2. Optimality gap indicator(s):

   a. To assess the quality of the solutions found by the SDAC algorithm, indicator(s) of the possible distance to optimality will be computed.
   b. The DA MCO Function updates implementation timescale is divided into phases:
      i. A phase to develop changes to the DA MCO Function;
      ii. A phase to test the DA MCO Function systems, including testing;
      iii. A phase to prepare the publication framework, which will be performed in parallel to the test phase;

    iv. The gap metric is planned to be available from February 2018.

3. Repeatability:

    a. Results of the price coupling algorithm should be able to be subjected to audits. The price coupling algorithm results and the inputs (order data and network constraints) shall be kept available. The algorithm will also be fitted with two new functionalities:
        i. During the course of the calculation process, information relevant be able to repeat the resulting solution will be logged;
        ii. The price coupling algorithm will support a dedicated mode, which allows repeating the historical results using the same version of the price coupling algorithm and on the same machine, considering historical input data and the information logged under point (i) above.
    b. The DA MCO Function updates implementation timescale will be divided into phases:
        i. A phase to develop changes to the DA MCO Function
        ii. A phase to test the DA MCO Function systems, including testing of potential impact on performance of the price coupling algorithm and the quality of the calculated results;
        iii. The auditability function shall be available for operation dependent on successful finalisation of the test phase (target February 2018).

4. Multi-NEMO arrangement requirement:

    a. To facilitate configurations with more than one NEMO in a bidding zone the DA MCO Function shall be updated to calculate NEMO hub to NEMO hub flows, within a bidding zone as well as between NEMO hubs of adjacent bidding zones ("Multi-NEMO Functionalities") to support the scheduled exchanges calculation and/or multi-NEMO arrangements function, where required, expected to include the steps:
        i. Collect input data at a NEMO level, instead of the currently supported bidding zone level;
        ii. Perform aggregation of NEMO input data to a bidding zone level;
        iii. Perform disaggregation of resulting output data to retrieve results for the individual NEMO in a bidding zone;
        iv. Provide bidding zone prices and net positions as an output of DA MCO Function;
        v. Calculate aggregate bidding zone to bidding zone flows (this is to support the scheduled exchanges calculation function, where required).
    b. The DA MCO Function updates implementation timescale will be divided into phases:
        i. A phase to develop changes to the DA MCO Function;
        ii. A phase to test the DA MCO Function system, including testing of the potential impact on performance of the price coupling algorithm and quality of the calculated results;
        iii. The Multi-NEMO solution function shall be put available for operation dependent on successful finalisation of test phase (target February 2018).
    c. The proposed timescale to implement the Multi-NEMO Functionalities is dependent on the following assumptions and preconditions:

i. No additional Multi-NEMO Functionalities will be requested. If additional Multi-NEMO Functionalities are requested, this may considerably impact the time needed for the phase to develop changes to the DA MCO Function;
ii. The developed solution will not have a significant negative impact on performance of the DA MCO Function or price coupling algorithm, leading to an inability to produce the necessary results in the given time constraints;
iii. The activation of new NEMOs using the Multi-NEMO Functionality will follow the change process set out in the Algorithm Proposal;
iv. NEMOs have not included scheduling areas as an initial requirement for the price coupling algorithm; if the inclusion of scheduling areas becomes an initial requirement for the price coupling algorithm, this would represent a significant change request, which will require full evaluation in terms of its impact on the performance of the price coupling algorithm and the timescale for implementation;
v. To achieve the proposed technical milestone for the DA MCO Function requirements must be specified by the relevant TSOs and NEMOs by July 2017, and these requirements should be mutually consistent and not imply major changes to the DA MCO Function.

5.1.4 Milestones for NEMOs local implementation of the DA MCO Function

1. Implementation of the DA MCO function shall be governed by regional timescales which are local and may vary in each region. In the following we explain the milestones for a NEMO to implement the DA MCO Function:
   a. Enter into the NEMO DA Operational Agreement for the management of the coupling phase in coordination with all NEMOs.
   b. Perform necessary testing and simulations in accordance with the Testing and Simulation Procedure of the NEMO DA Operational Agreement. Each NEMO, party to the NEMO DA Operational Agreement, shall individually ensure that, as of the date at which it starts coupling operations, its own systems, business processes, Market Rules and traded products involved in the SDAC ensure a smooth testing and implementation of the DA MCO Function.
2. To implement Single Day Ahead Coupling NEMOs shall enter into local, regional or European agreements with TSO, for the management of the pre and post coupling process, including where necessary, multi-NEMO arrangements foreseen by article 45 of the CACM Regulation. Implementation of such local arrangements, including pre and post coupling, are the responsibility of the respective TSOs and NEMOs, and are outside the scope of the MCO Plan.

5.2 Implementation of the ID MCO Function

1. The MCO Plan sets out the tasks necessary for all NEMOs to jointly set up and perform the ID MCO Function. The tasks include the adoption of the XBID Solution as the starting point the ID MCO Function (as described in Section 5.2.1), technical milestones for the implementation, testing and go-live of ID MCO Function (as described in Section 5.2.3), and contractual milestones to implement the necessary contracts and governance arrangements for the operation of the ID MCO Function (as described in Section 5.2.2).

2. In accordance with the CACM Regulation the MCO Plan includes a detailed description of the milestones and a proposed timescale for implementation of the ID MCO Functions, which shall not be longer than 12 months. In accordance with article 7(5) of the CACM Regulation the All NEMO Committee shall report to Agency on progress in meeting the technical and contractual milestones.

3. The MCO Plan shall be considered implemented when the technical and contractual milestones set out in this Section have been completed and the ID MCO Function is available for any NEMO to use.

4. In order for NEMOs to use the ID MCO Function they must in addition meet the necessary technical and contractual preconditions which are explained in Section 5.2.4.

5. NEMOs plan that the ID MCO Function implementation, and all technical and contractual milestones necessary for NEMOs to deliver the ID MCO Function, is targeted to completed by September 2017 and shall in any case not be longer than the 12 month MCO Plan implementation period.

6. The implementation of pre and post coupling activities necessary for the ID MCO Function to be used for capacity allocation on a bidding zone border are outside the scope of the MCO Plan.

5.2.1 Adoption of the XBID Solution as the ID MCO Function

1. The delivery of the ID MCO Function, in accordance with article 36(4) of the CACM Regulation, shall be based on the XBID Solution (IT assets and relevant procedures), which is the existing solution being developed for intraday coupling prior to entry into force of the CACM Regulation. Adoption by NEMOs of the XBID Solution as the basis for the ID MCO Function shall be contingent on agreement with TSOs (and NRAs where relevant) for the continuation and extension of the APCA.

2. Any impact on the MCO Plan completion date of a delayed approval and agreement with NRAs will be assessed by NEMOs at the time. NEMOs shall aim to limit this impact to the extent reasonable.

3. The steps required for the ID MCO Function becoming operational in a Member State include:
    a. contractual readiness (Section 5.2.2) and
    b. Technical readiness (Section 5.2.3)
    c. local implementation readiness (Section 5.2.4).

5.2.2 Contractual milestones for implementation of the ID MCO Function

1. The NEMO cooperation for delivering the ID MCO Function shall be based on the following contractual framework:

    a. The All NEMO Cooperation Agreement (“ANCA”);

b. PXs Cooperation Agreement ("PCA"), and its successor, the NEMO ID Operational Agreement;
c. All Party Cooperation Agreement - between NEMOs and TSOs ("APCA") and its successor, the Intraday Operational Agreement;
d. The back to back agreement between NEMOs and TSOs, which will become part of the Intraday Operational Agreement;
e. Contracts with ID MCO Function service providers:
    i. Master Service Agreement and Deliverable Service Agreements (DSAs) with the ID MCO Function System Supplier;
    ii. Contract with Multiprotocol Label Switching (MPLS) Service Provider;
    iii. Contract with PMO Service Provider.

2. Upon entry into force of the ANCA, the general governance framework shall be set by the ANCA. Specifically, under the ANCA, decisions by signatories to the PCA, and its successor the NEMO ID Operational Agreement, related to the implementation and operation of the Single Intraday Coupling, will be taken based on unanimity, and shall be escalated to the All NEMO Committee when unanimity cannot be reached.

3. NEMOs plan that all NEMOs designated to perform SIDC shall adhere to the ANCA by November 2017.

4. The PCA shall be open, subject to the terms of the PCA, to all NEMOs that are designated to perform SIDC. The PCA shall set forth the terms of the cooperation among NEMOs during the Development Phase of the ID MCO Function, for the development and the implementation of the Intraday System and the ID MCO Function. Decision making under the PCA shall be based on unanimity.

5. According to the PCA all participating NEMOs agree to develop and implement all elements of the ID MCO Function, enter into agreements to coordinate with TSOs, and to cooperate to steer, prioritise and manage development and implementation of the Intraday System and the ID MCO Function. The PCA entered into force in June 2014.

6. The APCA shall identify the roles and responsibilities of NEMOs and TSOs to design and develop the Intraday System and the ID MCO Function during the Development Phase. Pursuant to the APCA, NEMOs shall engage suitable ID MCO Function service providers for the delivery of the ID MCO Function, while adhering to the planning and budget agreed with the TSOs. The APCA shall provide for TSOs to define requirements and to monitor and test that such requirements are implemented. The APCA shall also provide for the interfaces with the local implementation projects (the "LIPs") and pre- and post-coupling procedures. Decision making under the APCA shall be based on unanimity. The APCA entered into force in July 2014.

7. The back to back agreement between NEMOs and TSOs, who are parties to APCA, reflects the fact that only NEMOs have entered into a contract with the ID MCO Function System Supplier for developing the ID MCO Function. During the Development Phase TSOs will test and accept functionalities without being a party to the contract with the ID MCO Function System Supplier.

This is because the NEMO contracts with Intraday System Supplier include features that are not part of the ID MCO Function but deliver TSO tasks under CACM (such as the CMM and the SM), and are not directly signed by TSOs. The purpose of the back to back agreement is to regulate the access of the TSOs to the ID MCO Function and the cooperation and information exchange between PXs and TSOs, and to pass through liabilities that may arise from any actions or omissions of the TSOs. The back to back agreement entered into force in March 2015.

8. All NEMOs designated for SIDC will be entitled and required to join, the ANCA, the NEMO ID Operational Agreement, the Intraday Operational Agreement and the contracts with the ID MCO Function service providers and the ID MCO Function System Supplier.

9. Prior to go-live, NEMOs shall establish the following contractual framework to underpin NEMO cooperation for SIDC:
    a. The All NEMO Cooperation Agreement;
    b. NEMO ID Operational Agreement among all NEMOs, replacing the PCA;
    c. Intraday Operational Agreement between all NEMOs and TSOs, replacing the APCA and back to back agreement;
    d. Contracts with ID MCO Function service providers, including the ID MCO Function System Supplier, MPLS communication system supplier and co-location service supplier.

10. All NEMOs and TSOs shall enter into the Intraday Operational Agreement, which will identify the roles and responsibilities of NEMOs and TSOs in the operation of SIDC. This will include a back to back agreement between NEMOs and TSOs which shall reflect the fact that only NEMOs have entered into a contract with the ID MCO Function System Supplier for the provision of the ID MCO Function. This is because the NEMO contracts with Intraday System Supplier include features that are not part of the ID MCO Function but deliver TSO tasks under CACM (such as the CMM and the SM), and are not directly signed by TSOs. The purpose of the back to back agreement is to ensure that TSOs and their explicit participants comply with the Intraday System requirements and to regulate the liability that may arise from any actions or omissions of the TSOs, their explicit participants and the behaviour and results of the Intraday System, in what relates to the CMM and SM parts of it that, as explained have been contracted to the Intraday System Supplier to provide a service to TSOs.

11. NEMOs plan that all NEMOs designated to perform SIDC shall enter into the Intraday Operational Agreement with TSOs by September 2017, or at the latest 3 months before such NEMO expects to join operationally the ID MCO Function. All NEMO designated for SIDC will be entitled to adhere to the Intraday Operational Agreement.

12. To be able to participate in SIDC, all NEMOs designated to perform SIDC shall become a party to the NEMO ID Operational Agreement. The NEMO ID Operational Agreement shall be based on the PCA. The main terms of this contract are summarised in Annex 3 of this MCO Plan.

13. The NEMO ID Operational Agreement shall set out the terms of NEMOs cooperation for the performance of ID MCO Function tasks provided under article 7 of the CACM Regulation. This contract will govern the NEMOs cooperation in respect of:

a. The daily management of the ID MCO Function operations;
b. The contractual management of the operational liabilities and results acceptance;
c. The rules for participation in the bodies established under the contract;
d. The management of cost reporting;
e. The rules for the selection of the ID MCO Function System Supplier;
f. The rules under which NEMOs will act towards ID MCO Function System Supplier;
g. The rules under which NEMOs will act towards TSOs in the context of the agreements signed among all participating NEMOs and participating TSOs for the SIDC.

14. NEMOs plan that all NEMOs designated to perform SIDC shall enter into the NEMO ID Operational Agreement by February 2018. The NEMO ID Operational Agreement may be concluded after ID MCO Function becomes operational with retroactive effect.

15. The NEMO ID Operational Agreement shall be supplemented by specific contracts for the provision of the ID MCO Function with ID MCO Function service providers that require to be signed by all participating ID NEMOs. These contracts will be the ones presently entered into, or being negotiated by the ID NEMOs with the ID MCO Function service providers.

16. The contracts with ID MCO Function System Supplier, as a service provider to the NEMOs that are signatories of those contracts, will regulate the development, use, operation and maintenance of the ID MCO Function. The contracts will include obligations to ensure equal treatment of the NEMOs and maintaining a level playing field between them.

17. NEMOs plan that all NEMOs designated to perform SIDC shall enter into the contracts with the ID MCO Function service providers and the ID MCO Function System Supplier in due time before such NEMO expects to join operationally the ID MCO Function.

5.2.3 Technical milestones for implementation of the ID MCO Function

1. Following adoption of the Intraday Solution as the ID MCO Function the NEMOs shall complete the following milestones to deliver the ID MCO Function. The milestones below are for implementation of the Intraday System, a part of which relates to TSO features (such as the CMM and SM), and a part of which relates to the ID MCO Function (the SOB).
2. The implementation timescale foresees two parallel streams to allow for a development of:
   a. the SOB and CMM; and,
   b. the SM.

   The implementation timescale foresees to align both streams prior start of User Acceptance Test.
3. The implementation timescale is divided into phases:
   a. A phase to develop the required technology and IT systems to be used for the ID MCO Function, which was completed in February 2016;
   b. A phase to test the first release (functional and technical scope defined by development contract) of the SOB and CMM ("test phase") that consists of the following milestones:
      i. Factory Acceptance Test (FAT) with monitoring role of NEMOs, which was successfully completed in May 2016;

ii. Integration Acceptance Test (IAT) with a leading role of NEMOs to ensure that LTS are compatible with the ID MCO Function, which was successfully completed in September 2016;
iii. User Acceptance Test (UAT) with a leading role of NEMOs to validate all functionalities and technical parameters of the ID MCO Function which are subject of the first release, and which consists of the following sub-phases:
    1. Functional Test to validate all functional requirements and conceptual principles, consisting of three executions to be completed by February 2017;
    2. Integration Test to validate all external interfaces of the ID MCO Function, consisting of three executions to be completed by April 2017;
    3. Emergency Plan Simulation, to validate the first release of the ID MCO Function System robustness, stability and recovery during and after an emergency situation where the ID MCO Function System is damaged or lost, consisting of one execution expected to be completed by June2017;
    4. Performance Test to validate that the ID MCO Function System is able to cope with both sustainable load and peak load, consisting of one execution expected to be completed by July 2017;
    5. Simulation Tests to validate that the ID MCO Function can follow all processes applicable for the Operation Phase, with a focus on the technical aspects of the system, consisting of two executions expected to be completed by August 2017.

c. SM Test Phases similar to those above but to be performed by the involved NEMOs and TSOs to guarantee the quality of the SM development, which was successfully completed by October 2016. UAT Phase for SM is identical as for the SOB and CMM.
d. A phase to test the second release (functional and technical scope managed under maintenance contract – Enhanced Shipper, System Monitoring, Data Intermediary) of the SOB, CMM and SM ("R1.2 test phase") that consists of the following milestones:
    i. User Acceptance Test (UAT) with a leading role of NEMOs to validate all functionalities and technical parameters of the ID MCO Function which are subject of the Release 1.2 (ID MCO Function R1.2), and which consists of the following sub-phases:
        1. Joint Functional and Integration Test to validate all functional requirements, conceptual principles and external interfaces of the ID MCO Function R1.2, to be completed by August 2017;
        2. Emergency Plan Simulation, to validate ID MCO Function R1.2 System robustness, stability and recovery during and after an emergency situation where the ID MCO Function R1.2 System is damaged or lost, consisting of one execution to be completed by August 2017;
        3. Simulation Tests to validate that the ID MCO Function R1.2 can follow all processes applicable for the Operation Phase, with a focus on the technical aspects of the system, consisting of two executions to be completed by September 2017;

4. Performance Test to validate that the ID MCO Function R1.2 System is able to cope with both sustainable load and peak load, consisting of one execution to be completed by October 2017.

e. Go-live preparation to ensure readiness of the operational staff, readiness of ID MCO Function for the start of the Operational Phase, and readiness of the LIPs (which are not part of this MCO Plan):
   i. The start of go-live preparation is dependent on successful finalisation of the UATs, readiness of the operational procedures and training of operational staff, readiness of contractual arrangements with the ID MCO Function System Supplier and ID MCO Function service providers and readiness of the Intraday Operational Agreement between NEMOs and TSOs;
   ii. Go-live preparation is expected to be completed by March 2018 in line with the milestones set out in Section 5.2.4 of this MCO Plan.

4. Any change to the ID MCO Function System implementation timescale shall be subject to a change management process established in the contracts with the ID MCO Function System Supplier.

5.2.4 Milestones for NEMOs local implementation of the ID MCO Function

1. Implementation of the ID MCO function shall be governed by timescales which are regional and may vary for each project. In the following we explain the milestones for a NEMO to ensure operational readiness:
   a. Readiness of the NEMO for the testing, to ensure that each NEMO has fulfilled all technical and procedural requirements for coordinated testing. NEMOs have to demonstrate their readiness to exchange data with the ID MCO Function System during the IAT and the ID MCO Function must pass UAT Integration tests.
   b. Completion of the Functional Integration Test to ensure all data between parties (TSOs and NEMOs) for implementation of SIDC on a specific border can exchanged and that all business processes for a specific border can be successfully processed.
   c. Completion of the Simulation Integration Test to demonstrate that all end to end business processes for a specific border, and in conjunction with other borders, are processed correctly.
   d. Official confirmation of go-live readiness, to confirm the full readiness of the NEMOs.
2. The first local implementation of the ID MCO Function are expected to be operational by March 2018. The NEMOs who are not operationally ready with regard to the timescale set out in Sections 5.2.3 and 5.2.4 will enter as soon as possible the same process for implementation of the NEMO readiness.

3. Single intraday Coupling will be implemented via local implementation projects (LIPs). The LIPs are national and/or regional in scope and are therefore not part of this MCO Plan. However, readiness of a LIP is a pre-condition to join Single Intraday Coupling operations.

4. To implement Single Intraday Coupling NEMOs shall enter into local, regional or European agreements with TSOs, for the management of the pre and post coupling process, including where necessary multi-NEMO arrangements, in accordance with article 57 of the CACM Regulation. Implementation of such local arrangements, including pre and post coupling, are the joint responsibility of the respective TSOs and NEMOs, and are outside the scope of the MCO Plan.

6 DAY AHEAD COOPERATION

6.1 Description of the DA MCO Function

6.1.1 Operation

1. The price coupling algorithm is operated in a decentralised manner and shall be based on the following principles:
    a. One single algorithm;
    b. One single set of input data for the whole coupled area;
    c. One single set of results for the whole coupled area;
    d. Input data to the algorithm is prepared and collected by each NEMO according to local Regulations and/or market contracts in a common format;
    e. The responsibility for the input data content is allocated to the respective input data provider (TSO or Market Participant) according to local regulations and/or market contracts;
    f. The complete input data file is received by the Coordinator/Backup Coordinator and all Operators (in an anonymised manner). This guarantees the transparency of the process since all parties guarantee that the same input data is used in the DA MCO results calculation process;
    g. Each Operator has the opportunity to compute the results in parallel;
    h. The single results of the DA MCO process, prior to each NEMO finally validating them, are validated and accepted by each responsible party (TSO and/or Market Participant) according to local regulations and/or market contracts;
    i. Each NEMO is responsible (in a decentralised manner) for its results, since each NEMO has the opportunity (directly or via its Servicing NEMO) to validate its results. The Servicing NEMO may share the relevant DA MCO Function results with the Serviced NEMO for the purposes of validation (including validation by each responsible party (TSO and/or Market Participant) according to local regulations and/or market contracts);
    j. Once results are finally accepted by all NEMOs (directly or via its Servicing NEMO) they are absolutely firm and there is no possibility for any NEMOs to contest the accepted results or to claim against the other NEMOs, including the Coordinator;
    k. The DA MCO results are repeatable and auditable.

6.1.2 NEMO Operational Roles

1. The roles, principles and rules related to the execution of operational roles performed by NEMOs including the performance of DA MCO Function will be set in the NEMO DA Operational Agreement.

2. There shall include the three following options for a NEMO designated for SDAC, to become an Operational NEMO for SDAC:
    a. As a DA MCO Function Asset Co-owner; or
    b. As a DA MCO Function Asset Licensee; or
    c. As a Serviced NEMO.

3. The options for a NEMO to become an Operational NEMO for SDAC will be developed and implemented in compliance with the requirements of the CACM Regulation.
4. With respect to the DA MCO Function, Operational NEMOs must perform one of the following roles:
    a. Coordinator or Backup Coordinator, whose responsibilities are explained in Section 6.1.2.1. below;
    b. Operator, whose responsibilities are explained in Section 6.1.2.2 below.

5. To perform the daily operations one NEMO is appointed as Coordinator and one NEMO is appointed as Backup Coordinator. The Backup Coordinator monitors the NEMO acting as Coordinator and is always prepared to take over the Coordinator role at any moment in case any problem appears in the Coordinator activities ("hot backup"). All other Operators may perform in parallel the same processes can also take over from the Coordinator the role if necessary ("warm backup").

6. The roles of Coordinator and Backup Coordinator are rotated. To perform as a Coordinator/Backup Coordinator, a NEMO must be a DA MCO Function Asset Co-Owner or a DA MCO Function Asset Licensee and satisfy specific technical requirements established by the NEMO DA Operations Committee and ratified by the All NEMO Committee in order to guarantee safe and reliable operation of the SDAC. The NEMOs playing the role receive reasonable compensation from all the benefiting NEMOs whose prices are formed during each SDAC session.

7. The Coordinator tasks are established in the NEMO DA Operational Agreement. Each NEMO is responsible for validating the individual results for its respective bidding areas. The transfer of the responsibility from the NEMOs to the corresponding TSO or Market Party is done according to local regulations and/or market contracts. Only Coordinator, Backup Coordinator and Operators may access the PMB.

8. In order to properly perform their tasks, in particular to manage correctly the maintenance of the DA MCO Function Assets, Coordinators, Backup Coordinators and Operators are required to be either a DA MCO Function Assets Co-owner or a DA MCO Function Assets Licensee. NEMOs that are a DA MCO Function Asset Co-Owner will remain responsible for managing the relationship with the DA MCO Function service providers and for managing the process to implement any agreed changes, with the DA MCO Function service providers.

9. The DA MCO Function Asset Co-Owners will undertake to follow the decision of the all concerned NEMOs with regard to change requests or other matters regarding the DA MCO Function service providers.

6.1.2.1 Coordinator/Backup Coordinator

1. A Coordinator is responsible for the following tasks during the operation of the DA MCO Function:
    a. Coordinate the operation of the DA MCO Function;

b. To perform the calculation of the market coupling results (this includes calculating the results, according to the operational procedures, by using the applied MCO operational assets and by using and processing the data on cross-zonal capacity as well as the bids received daily from all Operational NEMOs);
c. Act as single point of contact between the Operators and MCO service providers in case of an incident;
d. Intervene in the event of an incident and perform necessary coordinating actions;
e. File report summarizing the performed steps.

2. A Backup Coordinator is responsible for the following tasks during the DA Market Coupling Phase:
   a. Be ready to take over the Coordinator tasks at any moment during the Market Coupling Phase;
   b. To perform the calculation, the market coupling results (that includes calculating the results, according to the operational procedures, by using the applied DA MCO Function Assets and by using and processing the data on cross-zonal capacity as well as the bids received daily from all Operational NEMOs) and indicates any irregularity it may become aware of to the Coordinator;
   c. To provide towards the NEMO acting as Coordinator the needed information and support.

6.1.2.2 Operator

1. Operators perform the following main responsibilities:
   a. Provide all other Operators, including the Coordinator with the information needed for the calculation of the market coupling results for its markets or any serviced markets;
   b. Where it is calculating in parallel the market coupling results, to indicate any irregularity it may become aware of towards the Coordinator;
   c. To participate to the actions convened by the Coordinator and comply with commonly agreed decisions;
   d. To accept or reject the market coupling results for its own markets and serviced markets.
2. Any NEMOs can perform the Operator role provided it (a) is a DA MCO Function Asset Co-Owner or a DA MCO Function Asset Licensee, and (b) satisfies specific technical requirements established by the DA Operations Committee and ratified by the All NEMO Committee in order to guarantee safe and reliable operation of the DA market coupling.
3. The Operator role may be delegated, in accordance with article 81 of the CACM Regulation, by a NEMO signatory to the NEMO DA Operational Agreement to a Servicing NEMO. The precise scope of this delegation and the operational details that shall apply between a serviced and servicing NEMO shall be established under a bilateral agreement to be entered into by Serviced and Servicing NEMO, that shall be compliant with the operational rules and procedures set out in the NEMO DA Operational Agreement.
4. The main features of this delegation, that will be established in the NEMO DA Operational Agreement, are the following:
   a. The Servicing NEMO will collect all the network constraints, in accordance with regional agreements, and order information from the serviced NEMO and will perform all the MCO Function operational steps described under Section 6.1.3 in the name and on behalf of the serviced NEMO.
   b. There will be no direct communication between a Serviced NEMO and Operators during the operation of the Day Ahead Market Coupling sessions, other than through its Servicing

NEMO. The Serviced NEMO delegates at least its responsibility for real-time operational processes to the Servicing NEMO.

5. This delegation shall not impact the obligations of the Serviced NEMO under the CACM Regulation, the MCO Plan, or the NEMO DA Operational Agreement. Accordingly, the delegation shall not alter the responsibility that each NEMO undertakes for it results according to Section 6.1.1 of this MCO Plan.

6.1.3 Operational sequence of events in a Market Coupling session

1. A market coupling session consists of a sequence of process steps that need to respect agreed timings:
    a. At an agreed time, Operational NEMOs receive the network constraints from the corresponding TSOs. This reception process is decentralized and performed according to National Regulations and/or Market Contracts.
    b. The bid reception process is performed by all Operational NEMOs, including the opening and closing of the order acceptance period in a decentralised way according to their local regulations and/or market contracts. For operational reasons, there might be exceptionally delays in this bid reception process.
    c. At an agreed time, all Operational NEMOs submit to each other the set of network constraints (received from TSOs according to local regulation or market contracts) and the anonymised orders that they are responsible for.
    d. The results calculation process is started at a predefined moment by the Coordinator, the Backup Coordinator and all other Operators that want to do it.
    e. When results are obtained by the Coordinator they are shared with all Operators for NEMOs to validate them, potentially by comparing the Coordinator results with the results of their own run of the algorithm.
    f. Once this step is done, preliminary prices are published to the market, at a common time (unless the process has been delayed).
    g. Each NEMO can now disclose to its own market participants their specific results; where required by local regulations and/or market contracts, these should be used by them to perform a validation of the results.
    h. NEMOs disclose to relevant TSOs the information necessary for them to perform a validation of the results according to local regulations and/or contracts.
    i. Once the final validation is done, and shared with all other NEMOs by each NEMO, the results are declared firm and net position and area prices cannot be modified in any way.

2. The NEMO DA Operational Agreement will include a precise set of procedures describing each step in the market coupling process performed by Operational NEMOs. This includes backup mechanisms, information messages to participants and TSOs and reports that are generated in normal cases and in case there is any kind of incident. The NEMO DA Operational Agreement will also include provisions of how to update and to modify the procedures.

6.1.4 Validation of the Day Ahead Market Coupling session results

1. There are two types of validation:

a. The validation inherently performed by the Price Coupling Algorithm, to ensure that network constraints and orders characteristics are respected by the results.
b. The validation performed by all NEMOs, either alone or with a TSO and market participants.

2. These validations are done according to local regulations and/or market contracts and in accordance with article 48 of the CACM Regulation.

6.2 DA MCO Function systems

1. The systems needed to perform the DA MCO Function comprise the PMB; which in turn is comprised of two core sub-modules (the Broker and the Matcher) and the Algorithm (described above):
    a. The Broker module acts as the interface to every other PMB (to share data via a dedicated and secured cloud) and with local NEMO IT systems.
    b. The Matcher module makes all the data received from the Broker module available to the Price Coupling Algorithm and activates the Price Coupling Algorithm. This module also receives the results of the price coupling from the algorithm and forwards to the results to the Broker module.

2. In normal operational mode, the Broker module performs its actions automatically (files interchange, keep-alive messages, etc.). However, if necessary, the Broker module allows an Operator to manually launch all of these actions.

3. NEMOs use a dedicated and secured cloud-based communication solution to exchange data between each PMB.

4. All operational MCO Function systems shall comply with the performance and disaster recovery requirements as decided by the NEMOs under the NEMO DA Operational Agreement.

6.2.1 Change Control Procedure

1. Any change to the DA MCO Function Assets, any relevant changes to the connected local systems, as well as any changes to the format or nature of the input data to the market coupling system that may cause a risk of malfunction, a performance degradation or a problem for the continuity of operations, is subject to a DA Market Coupling change control procedure.

2. The impact of a change request must be assessed, before sign-off for implementation can be given. NEMOs are responsible to set acceptance criteria for implementation and to approve changes.

3. All NEMOs are entitled to request a change for their single use, or for the use by a subset of NEMOs, provided they finance the change to the registered DA MCO Function Assets and provided they meet the acceptance criteria for implementation and the approval by All NEMOs.

7 INTRADAY COOPERATION

7.1 Delivery of the ID MCO Function

7.1.1 Delivery of the ID MCO Function operation

7.1.1.1 Introduction

1. The Intraday Solution provides functionalities to perform the continuous matching of orders as well as the TSO functionalities in respect of capacity allocation taking into account the relevant available intraday cross-zonal capacity (the CMM), as well as the calculation of scheduled exchanges for shipping and settlement for TSOs (the SM) and central counterparties to ship and settle cross-zonal, cross-delivery area and cross-central counter party trades.
2. The Intraday System is a centralised system supporting 24/7 trading of Global Products. Global Products are eligible for matching in the Intraday System, as opposed to Local Products, which are matched solely in the respective LTS.
3. The ID MCO Function shall be based on the Intraday System, which consists of the following modules:
    a. Shared Order Book that supports the collection and matching of ID orders from all connected NEMOs LTS via Public Message Interface (PMI).
    b. Capacity Management Module that collects directly from TSOs the Cross-Zonal Capacity available at any instant for ID implicit trading, and ensures that the concluded ID trades respect such capacities. It also supports explicit cross-zonal capacity allocation function where it is requested by relevant NRAs.
    c. Shipping Module that computes the scheduled exchanges for shipping and settlement calculations for TSOs and central counter parties to ship and settle cross-zonal and cross-delivery area and cross-central counter party trades, where relevant.
4. The Intraday cross-zonal matching shall be based on the following principles:
    a. First-come first-served where the orders with highest buy price and the lowest sell price get served first given that also the cross zonal capacity constraints are respected if the Orders are in separate bidding zones.
    b. Cross zonal capacities and order books (OBK) are simultaneously updated in the CMM and SOB respectively on a continuous basis based on latest matching of orders and creation, modification and deletion of orders as well as capacity upgrades by TSOs.
    c. In addition, such simultaneous updates per bidding zone and towards the individual NEMO LTS connected to the Intraday Solution are exclusively provided via the central Intraday System.
    d. Input data (orders) to the matching submitted from the various NEMO LTSs is centralised in one SOB to enable full cross matching between the connected OBKs and combined with, where existing, explicit capacity allocation requests when it comes to utilization of cross zonal capacities available via CMM.
    e. Input data in the form of intraday cross zonal capacities between bidding zones to the matching is made available by the TSOs in CMM.
    f. All input data regarding bids/offers coming from the respective NEMOs individual LTSs are shared in the SOB in a fully anonymised manner to ensure both that competing NEMOs do not know which market participants connected to another NEMOs LTS are placing the

individual orders and in general to protect the confidentiality of individual market participants' orders.

g. The solution will be designed to accommodate possible intraday auctions in accordance with article 63 of the CACM regulation and capacity pricing in accordance with article 55 of the CACM Regulation.

5. The Intraday Solution also requires implementation of interfaces between the Intraday System and other NEMO and TSO systems. This includes the following interfaces:
    a. With NEMOs' LTSs. The SOB processes anonymised orders with support of the CMM:
        i. Market participants do not connect to the SOB directly, but via one or more LTSs of NEMOs, to trade Global Products.
        ii. Orders for Global Products are entered in NEMOs LTSs, which in turn connect to the SOB via the public message interface only by means of the intraday-dedicated MPLS network to transmit orders for Global Products and to receive global trades.
        iii. Matching of global orders is performed in the SOB, irrespective of whether the global orders have been entered for the same bidding zone, or for different delivery areas.
        iv. Matching of local orders is performed in NEMOs LTSs and does not form part of the Intraday System or the ID MCO function.
        v. The SOB module maintains a consolidated order book for all global orders (not local orders).
    b. With TSOs in order for TSOs to provide and receive relevant information for pre-coupling and post-coupling processes.
    c. With market participants to perform explicit allocation of cross-zonal capacities, where it is requested by relevant NRAs.
    d. With central counter parties acting under the responsibility of the NEMOs to ensure clearing and settlement of the matched orders as specified in the article 68 of the CACM Regulation.
6. Finally, each NEMO that is active in the Single Intraday Coupling shall be provided with access/connection to the SOB from the LTS of its own choosing via an PMI/Application Programme Interface (API) solution that secures equal access to and performance towards the SOB/CMM order matching process.
7. The Intraday System Supplier is delivering systems that meet TSOs requirements, that are not part of the ID MCO Function, and will be provided as a contractual service by NEMOs to all TSOs that are active in the Single Intraday Coupling. These include the CMM, the SM and the explicit capacity function, which allows the allocation of available cross-zonal capacity by TSOs to those participants that request it, where this arrangement is requested by NRAs pursuant to the CACM Regulation.

7.1.1.2 Cross-border matching during the continuous trading period

1. Trading period consists of a sequence of process steps that need to respect agreed timings:
    a. All NEMOs connected to the SOB/CMM via the common API and the LTS of its own choosing will be able to continually feed orders into the SOB and modify such orders as long as the instrument is open for trading.

b. Cross-zonal ID capacities are continually made available by the corresponding TSOs via the CMM from the cross zonal gate opening time until an agreed time for each bidding-zone to bidding-zone border when cross-zonal ID capacities cannot be changed any more for the delivery period.
c. All instruments on the Intraday System are traded continuously on every calendar day in accordance with the matching rules.
d. All NEMOs agree to respect the execution conditions available on the Intraday System, these will be further specified according to Section 7.2 of the MCO Plan and implemented and transparently detailed by the Intraday System Supplier.
e. At regular intervals, the SM computes and sends net positions and cross-zonal and delivery areas information to the relevant parties in order to enable settlement.
f. Each TSO individually, or in co-ordinated manner with other TSOs, runs its own procedures required for cross-zonal scheduling (Bidding Zone to Bidding Zone or intra Bidding Zone where there are multiple Delivery Areas within a Bidding Zone). Scheduling is based on the output of SM and/or the CMM and should respect the matched orders.

7.1.1.3 Validation of the Intraday Market Coupling results

1. The validation inherently performed by the matching algorithm makes sure that all the network constraints and the characteristics (price, volume, duration, etc.) and matching rules for the orders, are respected when matching of orders and pricing results are determined.

7.1.1.4 Delegation of tasks assigned to NEMOs in the Intraday Market Coupling

1. In accordance with article 81 of the CACM Regulation, NEMOs have the possibility of delegating tasks assigned under the CACM Regulation. The NEMO ID Operational Agreement shall not prevent services to be performed by one NEMO (the Servicing NEMO) for another NEMO (the Serviced NEMO) in the ID operations environment, provided that this arrangement respects any legal and technical requirements in the applicable contracts.

7.2 ID Matching concept

1. Matching in continuous trading
    a. Matching process in the continuous trading matching algorithm is deterministic.
    b. The term order matching is used to describe the creation of a trade, based on a buy and a sell order with compatible execution characteristics.
2. Execution Priority - execution of orders is based on the price-time-priority principle:
    a. Price - orders are always executed at the best price. The best buy order is always executed against the best sell order first (the best price for buy orders is the highest price, for sell orders it is the lowest price).
    b. Time - when an order is entered into a SOB, it is assigned a timestamp. This timestamp is used to prioritize orders with the same price limit. Orders with earlier timestamps are executed with a higher priority than orders with a later timestamp.
3. Price determination
    a. The price at which two orders are matched is the price of a trade.
    b. When two orders are matched in continuous trading, one of these orders must always be a newly entered or a modified existing order.

c. The trade price is the order price of the best order which is already in the SOB:
   i. If a newly entered buy order is matched against an existing sell order, the limit price of the sell order becomes the trade execution price.
   ii. If a newly entered sell order is matched against an existing buy order, the limit price of the buy order becomes the trade execution price.

4. Matching process
   a. The matching process usually starts with an order entry. A newly entered order is executed immediately if another order with the opposite side, for the same contract and crossed price within the price limit setup for the exchange already exists in the SOB. Otherwise it is, depending on the order's execution restriction, either deleted or entered into the SOB. When an order is matched in a trade, its quantity is reduced by the trade quantity.
   b. If an order can be executed, it may not necessarily be executed at a single price, but may sequentially generate multiple partial transactions at different prices against multiple different orders that already exist in the SOB. When an order was executed against the total available quantity (in other words: against all orders that were entered with this price limit) at a given price level, the next best price level becomes best and the newly entered order continues to be matched against orders entered at this price level. This process continues as long as the incoming order remains executable and has a positive order quantity. Subsequently the order is either deleted (if the order quantity has reached zero or depending on the execution restriction) or entered into the order book with its remaining quantity.
   c. The matching process can also be triggered by events leading to a crossed order book which may occur when TSOs release additional cross-zonal capacity or when cross-zonal trades release cross-zonal capacity. In such cases, all matchable orders will be matched at once by means of a matching process, with the calculation of a single price at which all orders are matched.

7.2.1 ID Systems

1. The primary ID Systems that are part of Intraday System are SOB, CMM, SM, and the PMI/API, e. g. for connecting the NEMOs LTSs to the SOB.
   a. The SOB is designed to enable matching of all order types that from time to time are permissible in Intraday Solution and submitted via the common PMI/API as part of the anonymized OBK per bidding zone from each of the NEMOs via the LTS of its choice. The matching of orders in the SOB, which represents the sum of all separate NEMOs OBKs, is done continually for all periods open for trading and respects both the capacity constraints given by the TSOs to the CMM, and the matching rules to combine the Implicit (NEMOs) OBKs with the separately given explicit cross zonal capacity orders.
   b. The CMM refers to a capacity allocation module which offers the ability to continually allocate cross zonal capacity at any given point in time:
      i. either to the best orders available in the SOB in case of Implicit capacity allocation (between bidding zones based on NEMO OBKs); or,
      ii. outside OBKs in case of Explicit (cross zonal capacity request) capacity allocation.
   c. The SM provides information from the relevant trades concluded within the Intraday Solution to each NEMO(s) involved in the trade and calculates the scheduled exchanges

necessary to perform the required shipping and settlement as part of the post-coupling process. The SM receives data from the SOB about all trades concluded between two (or more) bidding zones, as well as between multiple delivery areas within a bidding zone wherever that applies and between central counterparties within one bidding zone. Based on that information the SM ensures that information on the physical shipping from "source to sink" is transferred within given time stipulations to involved NEMOs and their central counterparties, shipping agents and TSOs, as well as necessary information to make financial handover between central counterparties.

d. The API/PMI is the common protocol/interface that enables each NEMO to connect to the SOB on equal terms, as well as separately is done for the explicit cross zonal capacity requests.

7.2.2 ID Procedures

1. The NEMO ID Operational Agreement will include a precise set of procedures that establish how all steps in the Single Intraday Coupling process are performed and how unexpected incidents are handled by each NEMO connected to the Intraday System, and how it is secured in accordance with equal treatment and performance requirements by the Intraday Service Provider. The NEMO ID Operational Agreement will also include provisions of how, and when necessary why, to update and to modify the procedures.
2. It is important to note that there will be an IDOA, signed by all participating NEMOs and all participating TSOs that should be aligned and coherent with the NEMO ID Operational Agreement for the Single Intraday Coupling to be able to be performed. This IDOA is not part of the MCO Plan since it needs to be developed and agreed together with TSOs. The IDOA between NEMOs and TSOs will cover completely the services provided by NEMOs to TSOs in the ID Coupling which are the CMM and most of the elements of the SM.
3. The NEMO ID Operation Agreement and IDOA will establish process to develop and modify procedures (NEMO procedures and NEMO-TSO procedures respectively), which will describe how the functionalities of the Intraday System will be used in order to perform market operation processes.

7.3 Governance

7.3.1 Change Control Procedure

1. ID change control procedures will be adopted in line with the principles of the DA change control procedure, adapted to the particular circumstances of the SIDC.

8 EXPECTED IMPACT OF CACM METHODOLOGIES

1. The CACM Regulation requires the MCO Plan to include a description of the expected impact of the terms and conditions or methodologies on the establishment and performance of the MCO Functions.
2. NEMOs do not expect that the capacity calculation region methodology prepared by TSOs in accordance with article 15(1) of the CACM Regulation will have an impact on the establishment and performance of the MCO Functions.
3. NEMOs do not expect that the generation and load data provision methodology developed by TSOs in accordance with article 16(1) of the CACM Regulation will have an impact on the establishment and performance of the MCO Functions because this is a pre-coupling task.
4. NEMOs do not expect that the common grid model methodology developed by TSOs in accordance with article 17(1) of the CACM Regulation will have an impact on the establishment and performance of the MCO Functions because this is a pre-coupling task.
5. NEMOs do not expect that the proposal for a harmonised capacity calculation methodology developed by TSOs in accordance with article 21(4) of the CACM Regulation will have an impact on the establishment and performance of the MCO Functions.
6. The back-up methodology, developed by NEMOs in accordance with article 36(3) of the CACM Regulation, was submitted to all regulatory authorities for approval in February 2017. NEMOs expect that the Back-up methodology will be approved by all regulatory authorities by August 2017. NEMOs do not expect that the Back-up methodology will impact the timescale for the establishment of the MCO Functions. NEMOs expect that the Back-up methodology will ensure that efficient and appropriate back-up procedures will be established for the performance of the MCO Functions.
7. The algorithm proposal developed by NEMOs in accordance with article 37(5) of the CACM Regulation (hereafter referred to as the "Algorithm Proposal", including the TSOs' and NEMOs' sets of requirements for algorithm development in accordance with article 37(1) of the CACM Regulation (hereafter referred to as the "Algorithm Requirements"), was submitted to all regulatory authorities for approval in February 2017. NEMOs expect that the Algorithm Proposal and Algorithm Requirements will be approved by all regulatory authorities by August 2017.
8. NEMOs do not expect that the Algorithm Proposal and Algorithm Requirements will impact the timescale for the establishment of the MCO Functions. This is because developments necessary to meet the initial requirements described in the Algorithm Requirements have already been taken into consideration in this MCO Plan. The future requirements described in the Algorithm Requirements will be implemented after the MCO Plan implementation timescale in accordance with the procedures established in the Algorithm Proposal. NEMOs do not expect the initial requirements to impact the performance of the DA MCO Function and the ID MCO Function. NEMOs do expect the future requirements described in the Algorithm Requirements to impact the performance of the DA MCO Function and ID MCO Function. To mitigate and manage the potential impact of any future requirements on algorithm performance NEMOs have, in the

Algorithm Proposal, proposed measures to assess and control algorithm performance and to establish a transparent and robust change management procedure.

9. The proposal for products (hereafter referred to as the "Products Proposal") that can be taken into account by NEMOs in the single day-ahead and intraday coupling process developed by NEMOs in accordance with articles 40 and 53 of the CACM Regulation, was submitted to all regulatory authorities for approval in February 2017. NEMOs expect that the Products Proposal will be approved by all regulatory authorities by August 2017.

10. NEMOs do not expect that the Products Proposal will impact the timescale for the establishment of the MCO Functions. This is because the developments necessary to take into account the products listed in the Products Proposal have already been taken into consideration in this MCO Plan. NEMOs do not expect that the products listed in the Products Proposal will necessarily impact the performance of the MCO Functions. To mitigate and manage the potential impact of the products listed in the Products Proposal on performance of the MCO Functions, the Algorithm Proposal, proposes measures to assess and control algorithm performance. Furthermore, to mitigate and manage the potential impact of the introduction of any new products on performance of the MCO Functions, the Algorithm Proposal establishes a transparent and robust change management procedure.

11. The maximum and minimum prices methodology developed by NEMOs in accordance with articles 41(1) and 54(2) of the CACM Regulation, was submitted to all regulatory authorities for approval in February 2017. NEMOs expect that the maximum and minimum prices methodology will be approved by all regulatory authorities by August 2017.

12. NEMOs do not expect that the maximum and minimum prices methodology will impact the timescale for the establishment of the MCO Functions because the proposed maximum and minimum prices have already been taken into account in this MCO Plan. NEMOs do not expect the maximum and minimum prices methodology, or more specifically the proposed level of the maximum and minimum prices, to affect the performance of the MCO Functions.

13. NEMOs expect that the intraday capacity pricing methodology developed by TSOs in accordance with article 55(1) of the CACM methodology will be submitted to all regulatory authorities for approval by August 2017. NEMOs expect that the intraday capacity pricing methodology will be approved by all NRAs by February 2018.

14. NEMOs do not expect that the intraday capacity pricing methodology to impact the timescale for the establishment of the MCO Functions. This is because we expect that the MCO Functions will be implemented before the intraday capacity pricing methodology is approved by NRAs. NEMOs expect that the intraday capacity pricing methodology will affect the performance of the ID MCO Function. To mitigate and manage the potential impact of the intraday capacity pricing methodology on the performance of the ID MCO Function, NEMOs propose to follow the robust and transparent change management procedures established in accordance with the Algorithm Proposal and this MCO Plan.

15. The intraday cross–zonal gate opening and intraday cross-zonal gate closure times (hereafter referred to as the "TSO ID Gate Opening and Closing Proposal") developed by TSOs in accordance with article 59(1) of the CACM Regulation was submitted to all regulatory authorities for approval

in December 2016. NEMOs expect that the intraday cross-zonal gate opening and intraday cross-zonal gate closure times will be approved by all regulatory authorities by June 2017.

16. NEMOs do not expect that the TSO ID Gate Opening and Closing Proposal will impact the timescale for the establishment of the ID MCO Function. NEMOs expect that the TSO ID Gate Opening and Closing Proposal will impact the performance of the ID MCO Function by setting limits on the time period for which the ID MCO Function is able to allocate cross-zonal capacity.

17. The day-ahead firmness deadline (hereafter referred to as the "TSO DA Firmness Deadline Proposal") developed by TSOs in accordance with article 69 of the CACM Regulation was submitted to all regulatory authorities for approval in December 2016. NEMOs expect that the TSO DA Firmness Deadline Proposal will be approved by all regulatory authorities by June 2017.

18. NEMOs do not expect that the TSO DA Firmness Deadline Proposal will impact on the timescale for the establishment DA MCO Function or the performance of the DA MCO Function. This is because the day-ahead firmness deadline proposed by the TSOs is in line with existing solutions and has been taken into consideration in this MCO Plan.

19. NEMOs do not expect that the congestion income distribution methodology developed by TSOs in accordance with article 73(1) of the CACM Regulation will have an impact on the establishment and performance of the MCO Functions because this is a post coupling task.

20. NEMOs expect that TSOs in each capacity calculation region will submit a common capacity calculation methodology, developed in accordance with article 20(2) of the CACM Regulation, to the relevant regulatory authorities no later than 10 months after the approval of the proposal for capacity calculation regions.

21. Any impact on the MCO function implementation timescale or algorithm performance can only be evaluated once the new methodologies have been defined. To mitigate and manage the potential impact of the regional capacity calculation methodologies on the performance of the MCO Functions, NEMOs propose to follow the robust and transparent change management procedures established in accordance with the Algorithm Proposal and this MCO Plan.

22. NEMOs do not expect that the regional methodologies for coordinated redispatching and countertrading developed by TSOs in accordance with article 35(1) of the CACM Regulation will impact on the establishment and performance of the MCO Functions as we do not expect that TSO cross-border actions will take place in the same timeframe as the operation of the MCO Functions.

23. NEMOs expect that TSOs will submit the common methodologies for the calculation of scheduled exchanges, developed in accordance with articles 43(1) and 56(1) of the CACM Regulation, to regulatory authorities by December 2016. The TSO proposal may have an impact on the establishment and performance of the MCO Functions. This is because the current TSO proposal seeks to make the calculation of the scheduled exchanges a responsibility of the MCO Functions.

24. NEMOs do not expect that the regional fallback procedures, developed by TSOs in accordance with article 44 of the CACM Regulation will impact on the timescale for the establishment and the performance of the DA MCO Function. This is because the fallback procedures are intended to ensure efficient, transparent and non-discriminatory capacity allocation in the event that the single day-ahead coupling process is unable to produce results.

25. NEMOs expect that TSOs and NEMOs will jointly submit a common proposal for complementary regional auctions, jointly developed by TSOs and NEMOs in accordance with article 63(1) of the CACM regulation, to the relevant regulatory authorities by February 2017 at the earliest.
26. NEMOs do not expect that the joint proposals for complementary regional auctions will necessarily impact the timescale for the establishment of the ID MCO Function. This is because we expect the ID MCO Function to be implemented before we know the detailed requirements related to the implementation of complementary regional auctions. Complementary regional auctions may impact the performance of the ID MCO Functions. To mitigate and manage the potential impact of the complementary regional auctions on the performance of the ID MCO Functions, NEMOs propose to follow the robust and transparent change management procedures established in accordance with the Algorithm Proposal and this MCO Plan.
27. NEMOs do not expect proposals of individual TSOs for a review of the bidding zone configuration in accordance with article 32(1)(d) of the CACM Regulation will impact on the timescale for the establishment of the MCO Functions. A decision to amend the bidding zone configuration may impact the performance of the MCO Functions. To mitigate and manage the potential impact of a decision to amend the bidding zone configuration on the performance of the MCO Functions, NEMOs propose to follow the robust and transparent change management procedures established in accordance with the Algorithm Proposal and this MCO Plan.
28. NEMOs do not expect that proposal for cross-zonal capacity allocation and other arrangements developed by TSOs in accordance with articles 45 and 57 of the CACM Regulation will impact the on the timescale for the establishment and the performance of the MCO Functions. This is because the MCO Functions are being developed to be able to accommodate bidding zones with more than one NEMO and/or interconnectors that are not operated by certified TSOs.
29. In case the proposed methodologies are not approved in the indicated timelines, or are amended in an unforeseen manner, or have unforeseen consequences, NEMOs shall assess the impact on the establishment and performance of the MCO Functions and propose remedial measures to mitigate the effects.

9 ANNEX 1 – Summary of Interim NEMO Cooperation Agreement (INCA)

Terms of the contract	
Object	An interim contractual framework for the governance and coordination of common European NEMO responsibilities by a NEMO Committee regarding the implementation of the MCO Plan.
Scope	To establish an interim framework to facilitate the necessary cooperation between designated NEMOs with respect to the performance of all common tasks that need to be performed in connection with: a) The development and submission of the MCO Plan in accordance with article 7 (3) of the CACM Regulation; b) The development and submission of other appropriate terms and conditions and/or methodologies required in accordance with article 9 (6) of the CACM Regulation; c) The development of the Enduring Cooperation Agreement as proposed in the MCO Plan; d) Any additional tasks as may be agreed unanimously from time to time by the Parties.
Parties	All NEMOs
Obligations of the parties	- Best effort obligation and good faith cooperation for the achievement of the Scope of the INCA - Cooperation based on the principles of non-discrimination and subsidiarity
Applicable law	Belgian law
Dispute resolution	- Amicable settlement by referring the matter in Dispute to the Committee established by the INCA; - In the event of failure, the Committee shall solicit ACER for a non-binding opinion on the Dispute and; - At last resort, arbitration under the ICC Rules of Arbitration in Brussels.

10 ANNEX 2 – Summary of DA Contracts

10.1 Summary of the draft NEMO DA Operational Agreement

1. Purpose

The NEMO DA Operational Agreement ("**NEMO DAOA**") shall be entered into by all DA Operational NEMOs, including Serviced NEMOs. Entering into the NEMO DAOA is a precondition for being an Operational NEMO.

The purpose of the NEMO DAOA is to set forth the main principles of cooperation between Operational NEMOs in respect of DA MCO Function for Single Day Ahead Coupling, and the terms and conditions under which the parties will:

- Design, test and request changes to the DA MCO Function operational assets (including the DA MCO Function assets, subject to the agreement between the DA MCO Function Assets Co-Owners); and,
- Secure performance and operation of the DA MCO Function

The NEMO designation and the signature of the ANCA will be conditions for becoming a Party to the NEMO DAOA.

2. General principles

- Participation in Single Day Ahead Coupling is based on the following options. An Operational NEMO may participate as:
    - a Coordinator/Backup Coordinator/Operator;
    - only an Operator; or,
    - a Serviced NEMO.
- As a consequence of the fundamental principle of subsidiarity and the agreed decentralised approach: (i) the operation and results of a NEMO's own trading platform and of the common NEMO DAOA market coupling systems remain the individual responsibility of each NEMO (ii) necessary arrangements with TSOs, NRAs and third parties to have cross-border capacities made available and to ensure the related cross-border shipping are the local responsibilities of NEMOs.
- Congestion revenue shall be reattributed to TSOs or to NRAs in accordance to applicable legal provisions.
- The Parties agree to evaluate the performance of the NEMOs DAOA at least every two years.
- Delegation is possible by one NEMO to another NEMO of MCO Functions in accordance with the MCO Plan and article 81 of the CACM Regulation.

3. Cooperation in respect of DA MCO Function Assets and Individual Assets

- The Parties to the NEMO DAOA jointly make proposals on the design and development of the DA MCO Function Assets that are effectively developed and maintained by the DA MCO Function Assets Co-Owners.
- The DA MCO Function Assets, developed and maintained by the DA MCO Function Assets Co-Owners, are provided “as is” without any warranty of fitness for any particular purpose.
- Any proposal of changes to the DA MCO Function Assets shall be subject to the NEMO DAOA change control procedures.
- The budget/costs and scope of any proposal of changes to the DA MCO Function Assets required for the SDAC is agreed by the DA MCO Function Assets Co-Owners approved by the All NEMO Committee.
- The DA MCO Function Assets (the hardware excluded) shall only be put in operation after fulfilment of the acceptance criteria regarding testing and simulation set by the DA Operational Committee of the NEMO DAOA.

4. Daily operation

- The designated Coordinator coordinates for a given day and supervises the operation of the Single DA Coupling MCO Function operations. The Coordinator and Backup Coordinator will daily perform simultaneously these operations in accordance with the NEMO DAOA Operational Manual. Operators have the right to perform the Single DA Coupling price calculation operations in shadow mode.
- Each Party for whom Single DA Coupling operations is Operational provides, if applicable and not assigned to another Party: (i) the network features from the relevant TSOs to take into account for market coupling and (ii) the anonymous and aggregated order books per Bidding Zone related to the orders market participants have submitted on its trading platforms.
- The Market Coupling Results calculated by the Coordinator shall always prevail once accepted by each Operator (including the Coordinator itself and the Backup coordinator). However, each party acting as Operator has the right to accept or reject the Market Coupling Results according to the NEMO DAOA Operational Manual. No reaction from a Party is considered as a deemed acceptance of the Market Coupling Results. Market Coupling Results cannot be published prior to an agreed time in the Procedures. Each Operator, Coordinator or Backup Coordinator has the right to reject the Market Coupling Results and decouple in compliance with the agreed procedures, but this should be a last resort solution.
- Decoupling in compliance with the agreed procedures is not considered a default nor a contractual breach by the parties to the NEMO DAOA. Such decoupling is an agreed backup procedure and as a consequence it does not lead in itself to any indemnification obligation for damages incurred by the decoupling.
- No Party may undertake to any third party that the SDAC is conducted under an obligation of result.

- In case of an incident, the Coordinator shall convene a call with the Backup Coordinator and Operators to jointly take a decision to solve the incident in accordance with the procedures in the NEMO DAOA Operational Manual. Such emergency calls shall be recorded.
- If the Coordinator fails to perform, the Backup Coordinator takes over the Coordinator role. Parties can decide to suspend a Party as Coordinator/Backup Coordinator.
- Each Party that is directly performing the Operator role shall participate as Coordinator/Backup Coordinator on an equal shared number of days and on a rotating basis provided that the technical conditions established in the NEMO DAOA and in the Operational Manual for acting as Coordinator and Backup Coordinator are fulfilled.
- A Party acting as a Coordinator/Backup Coordinator will be remunerated as a Common Cost.
- The NEMO DAOA Operational Manual will establish the full operational processes and procedures.

5. Adherence

- Adherence to NEMO DAOA by a NEMO is subject to:
    - written evidence of its designation as NEMO,
    - signature of the ANCA,
    - participation in accordance with the CACM Regulation and the relevant NRA decisions.

Costs incurred by other parties due to the accession/geographic extension of the SDAC shall be recoverable from the adhering NEMO.

6. Confidentiality and communication to third parties

- All information under this Agreement (including Market Data of the Parties) is Confidential Information unless otherwise specified. Market Data provided by NEMOs to the MCO, market prices and matched orders remain the exclusive property of the providing NEMO (or as otherwise established under relevant national regulation).
- NEMOs are not entitled to access or analyse Market Data of other NEMOs except for the strict purpose of operational or performance management or development where this is undertaken as part of jointly controlled process under the Steering Committee.
- NEMOs may use the Market Data of other NEMOs for the purposes of performing simulations on their own markets provided that this does not prejudice competition between NEMOs. NEMOs may publish the results of their simulations in terms of prices and net positions of their own markets.
- Taking into account confidentiality, Parties shall be free to express written or oral positions or opinions about all NEMO DAOA related matters in their own name, provided they do not prejudice or negatively affect the collective and/or individual interests or the reputation of the other Parties.
- Commonly agreed communication after an incident in coordinated matching however each Party being liable for its own order book, and is, as such free to communicate with its clients/customers

provided that such communication does not impair the commonly agreed position and uses as much as possible the commonly agreed communication.

7. Liability

- Since the Coordinator, the Backup Coordinator and Operator(s) (i) have access at the same time to the required information to assess due performance of Single DA Coupling MCO Function operations and have the possibility to intervene to ensure due performance of those operations, and (ii) have the possibility to run or check in shadow mode in real time the matching algorithm, and (iii) have the right to Decouple itself and/or Decouple its Serviced NEMOs; all Operational NEMOs waive any right or remedy against each other for any financial compensation for damages incurred by a wrongful act or omission under the Coordinator, Backup Coordinator or Operator role.
- Overall liability under this Agreement including hold harmless is capped per calendar year for all damages with certain exceptions.
- No joint and several liability.
- Waiver of any rights to request financial compensation for damages related to the production of Market Coupling Results such as, but not limited to, damages deriving from:
  - a wrongful act or omission under the Coordinator, Backup Coordinator or Operator role;
  - any error or malfunctioning of DA MCO Function Assets;
  - the absence of Market Coupling Results;
  - decoupling;
  - any decision taken within the Incident Committee.

8. Entry into force, Term and Termination

- The Agreement shall enter into force when signed by all the Parties for an indefinite period.
- Full termination of the Agreement is possible by mutual agreement only.
- A Party may exit from the Agreement in the following circumstances:
  - With 12 months’ notice without any motivation being due;
  - With 6 months’ notice in case of failure to reach an agreement motivated by a change due to regulatory reasons.
- The parties may terminate this Agreement in respect of a party:
  - In the event of bankruptcy, material breach of this Agreement and subsequent non-compliance, cease of business etc.;
  - in the event the party is no longer designated as a NEMO for day-ahead.
- The exiting Party shall use its best efforts to mitigate the damage of the termination and shall assist and cooperate in measures of continuity for the remaining parties.

9. Governing law and Dispute resolution

- Governing law: Belgian law.
- Amicable settlement by the CEOs (within 1 month).
- If the matter falls under the scope of competence of the All NEMO Committee, it may be escalated to the all NEMO Committee.
- In other cases:
  - amicable settlement by the parties;
  - ACER nonbinding opinion;
  - mediation;
  - ICC arbitration.

10.2 Summary of contract with DA MCO Function service provider – PMB Service Provider

Terms of the contract	
Object	*The Maintenance and Support Contract sets forth the terms & conditions under which the PMB Service Provider shall provide the Maintenance and Support Services to the benefit of the DA MCO Function Assets Co-Owners*
Parties	One DA MCO Function Assets Co-owner (in its name and for the account of all other DA MCO Assets Co-owners), the PMB Service Provider
Scope	Maintenance and Support Services; Incident Management Services; Change Request Services; and Extended Testing Phase Services.

10.3 Summary of contract with DA MCO Function service provider – Algorithm Service Provider

Terms of the contract	
Object	*The Maintenance and Support Contract sets forth the terms & conditions under which the Algorithm Service Provider shall provide the Maintenance and support services to the benefit of DA MCO Function Assets Co-Owners.*
Parties	One DA MCO Function Assets Co-owner (in its name and for the account of all other DA MCO Assets Co-owners), the Algorithm Service Provider
Obligations of the parties	• Maintenance and Support Services; • Incident Management Services; • Change Request Services; and • Consulting Services.

10.4 Summary of contract with DA MCO Function service provider – Communication Network Supplier

Terms of the contract	
Object	*The Contract sets forth the terms & conditions under which the Communication Network Supplier shall provide the services to the benefit of DA MCO Function Assets Co-Owners.*
Parties	One DA MCO Function Assets Co-owner (in its name and for the account of all other DA MCO Assets Co-owners), the Algorithm Service Provider
Scope	The Service Level Agreement covers the following services: • *Service Delivery Agreement;* • *Fault Handling Agreement;* • *Service Availability Agreement;* • *Service Quality;* • *Packet loss agreement;* • *Jitter level agreement;* • *Round trip delays.*

11 ANNEX 3 – Summary of ID Contracts

11.1 Summary of the draft NEMO ID Operational Agreement

1. Purpose

- The ID Operational Agreement is an agreement to be entered into by all NEMO's performing the ID MCO function.
- It sets forth the main principles of cooperation in respect of ID MCO Function for Single Intraday Coupling (cross border implicit intraday continuous trading to be implemented in EU countries and electrically connected countries in accordance with the Agreement, hereafter Single Intraday Coupling) setting the terms and conditions under which the Parties will:
    - Design, test and request changes to the ID MCO Function IT assets, and
    - Operate the ID MCO Function;
    - Connect their Trading Systems to the Intraday System.
- The NEMO designation and the signature of the ANCA will be conditions for becoming a Party to the NEMO IDOA.
- The NEMO IDOA also regulates the relationship of the NEMOs:
    - with the common service providers; and
    - with the TSOs for the Intraday Solution.

2. General principles

- The NEMO IDOA is open to any designated NEMO having signed the ANCA.
- Equal treatment amongst market participants, NEMOs, TSOs and their explicit participants.
- All parties to the NEMO IDOA shall enter into the relevant service agreements with the common service providers.
- The Parties agree to evaluate the performance of the NEMOs IDOA at least yearly.

3. Cooperation in respect of ID MCO Function Assets and Individual Assets

- The Parties jointly design the ID MCO Function Assets. Any changes to the ID MCO Function Assets are subject to the change control procedure, approval by the relevant Committee.
- Local trading systems are defined as Individual Assets. A Party may contract the development of specific functionalities of a trading system connected to the Intraday System and developed by the Intraday System Supplier provided that:
    - the Intraday System Supplier has undertaken appropriate commitments to ensure that (a) the granting of rights by the Intraday System Supplier shall in no way prevent the other NEMOs to be granted at least the same rights in the specific functionalities; and (b) NEMOs who have procured or wish to procure a trading system connected to the Intraday System and developed by the Intraday System Supplier are treated in a fair and non-discriminatory manner by the Intraday System Supplier in respect of the costs charged for and the terms and modalities applicable to any granted rights.
    - The possibility is guaranteed towards other parties to convert upon agreement of all parties such rights into a joint license or joint ownership.

- The costs incurred in the context of the design, development, testing, implementation and maintenance of the ID MCO Function Assets shall be approved by the relevant committee.
- The ID MCO Function systems shall only be put in operation after fulfilment of the acceptance criteria regarding testing and simulation.

4. Permanent operation of the Intraday System

- The Agreement shall at least include detailed procedures for:
    - stopping and restarting the Intraday System, including for connection of Local Trading Solutions; and
    - Incident Committee (comprising Operational NEMOs and the Intraday System Supplier).

5. Adherence

- Any NEMO designated for Intraday having signed the ANCA is entitled to adhere subject to participation in accordance with the CACM Regulation and the relevant NRA decisions.

6. Governance

- The Parties shall setup governance structure in order to discuss and decide on any matter related to the Agreement. Changes to the Agreement can only be done by the legal representatives of the Parties following approval by unanimous decision.
- Decisions will be taken by unanimity. In case of disagreement on certain issues, an escalation procedure to the All NEMO Committee is foreseen.

7. Confidentiality and communication to third parties

- All information under this Agreement (including Market Data of the Parties) is Confidential Information unless otherwise specified. Market Data provided by NEMOs to the ID MCO Function, market prices and matched orders remain the exclusive property of the providing NEMO (or as otherwise established under relevant national regulation).
- NEMOs are not entitled to access or analyse Market Data of other NEMOs except for the strict purpose of operational or performance management or development where this is undertaken as part of jointly controlled process under the relevant committee.
- Taking into account confidentiality, Parties shall be free to express written or oral positions or opinions about all IDOA related matters in their own name, provided they do not prejudice or negatively affect the collective and/or individual interests or the reputation of the other Parties.
- NEMOs shall commonly agree communication after an incident in coordinated matching. However, each Party is liable for its own order book, and is, as such free to communicate with its clients/customers provided that such communication does not impair the commonly agreed position and uses as much as possible the commonly agreed communication.

8. Liability

- No joint and several liability;
- Incidental, indirect or consequential damages are excluded;
- The total indemnification obligation of a party shall be limited, with certain exceptions for third party claims, such as the claims raised by common service providers.

9. Entry into force, Term and Termination

- The Agreement shall enter into force when signed by all the Parties for an indefinite period;
- Full termination of the Agreement is possible by mutual agreement only;
- A Party may exit from the Agreement in the following circumstances:
    - With 8 months' notice without any motivation being due;
    - With 6 months' notice in case of failure to reach an agreement motivated by a change due to regulatory reasons.
- The parties may terminate this agreement in respect of a party:
    - In the event of such party bankruptcy, material breach of this Agreement and subsequent non-compliance, cease of business etc.;
    - In the event of a party is no longer designated as a NEMO for Intraday.
- The exiting Party shall use its best efforts to mitigate the damage of the termination and shall assist and cooperate in measures of continuity for the remaining parties.

10. Governing law and Dispute resolution

- Governing law: Belgian law;
- For contractual disputes, a dispute resolution process will be established;
- Certain matters may be escalated to All NEMO Committee.

11.2 Summary of NEMO Cooperation Agreement – PCA

Terms of the contract	
Object	*Determine the terms and conditions of the cooperation for the further design, the development, the implementation and the operation of the Intraday Solution in compliance with the Intraday Model.*
Parties	*ID designated NEMOs*
Scope	Parties commit to: o Jointly steer, prioritise and manage the design and development of the joint components and the performance of the parties in compliance with the Intraday Solution; o Ensure the development, implementation, operation and maintenance of the joint components in compliance with the Intraday Solution; o Cooperate to couple their own intraday continuous market places in accordance with the Intraday Model and the Intraday Solution;

11.3 Summary of contract with ID MCO Function service provider – ID System Supplier

Terms of the contract	
Object	The agreement sets forth the main terms and conditions under which the relevant NEMOs assign the provision of the services to the ID System Supplier.
Parties	All ID designated NEMOs and the Intraday System Supplier
Scope	Capacity Management Module, Shipping Module and Shared Order Book services: • Development • Operating License • Maintenance • Hosting

11.4 Summary of contract with ID MCO Function service provider – Communication Network Supplier

Terms of the contract	
Object	MPLS Communication Network provides an equal and secure communication network between ID System and Local Trading Solutions (LTSs), regardless of the location of the LTSs. The General Terms and Conditions and the contract annexes apply to any provision of services by the Communication Network Supplier; including equipment delivered by the Communication Network Supplier, as indicated in the order form for each NEMO (LTS end point) and for central point represented by ID System). The SLA sets out the SLA metrics and service credit regime for various services and covers Off-Net Services only where specifically referenced.
Parties	The Communication Network Supplier and ID designated NEMOs
Scope	a) implementation services, including 1. the services related to project management 2. installation services b) operational services, including 1. Service Delivery 2. Fault Handling

Annexure - 4

Report of the Expert Group

Transmission Corridor Allocation

To

Multiple Power Exchanges

for

Collective Transactions

28.01.2016

January 2016

Submitted in Compliance to CERC Order dated 30th April 2015 in Petition No. 158/MP/2013

To

Secretary

Central Electricity Regulatory Commission

3rd& 4th Floor, Chanderlok Building, 36 Janpath

New Delhi-110001

Reference: CERC Order dated 30th April, 2015 in Petition No. 158/MP/2013

Subject: Report of the Expert Group to examine methodologies for Transmission Corridor Allocation to Power Exchanges

Madam,

Hon'ble CERC vide Order dated 30th April, 2015 in Petition No. 158/MP/2013 directed an Expert Group to examine methodologies for Transmission Corridor Allocation to Power Exchanges for Collective Transactions and submit a report.

The issue was examined and deliberated by the Expert Group. Simulation studies were also carried out and discussed. The Report along with the analysis, conclusions and recommendations of the Expert Group are enclosed herewith for the perusal of the Hon'ble Commission.

Dr. S.K. Chatterjee	**S.K. Soonee**
Joint Chief (Regulatory Affairs)	Chief Executive Officer, POSOCO
Member Secretary of the Expert Group	Chairman of the Expert Group

Acknowledgement

The Expert Group constituted in pursuance to the CERC Order dated 30th April 2015 in Petition No. 158/MP/2013 to examine methodologies for Transmission Corridor Allocation to Power Exchanges for Collective Transactions held four meetings to examine and deliberate the issues.

The Expert Group wishes to place on record the sincere appreciation of the contribution made by the co-opted members Prof. Abhijit R. Abhyankar, IIT Delhi and Dr. Puneet Chitkara, Consultant, KPMG who along with Shri Deep Kiran, Research Scholar, IIT Delhi also carried out simulation studies to examine various methods of corridor allocation.

The Expert Group also acknowledges and appreciates the contribution made by Dr. Nicholas Ryan, Associate Professor Yale University, a special invitee, for presenting his studies on the intricacies of the Indian Electricity Market particularly, the Power Exchange Operations and suggesting improvements in the current transmission corridor allocation mechanism.

The Expert Group acknowledges the valuable inputs provided by the NLDC team comprising of Sh. S.S. Barpanda, Sh. M.K. Agarwal, Sh. S.C. Saxena and Sh. Kaushik Dey.

Expert Group also acknowledges the analytical inputs provided by the CERC team comprising of Sh. V.V. Sharma Sr. Advisor (Power Markets), Sh. Mayank Shekhar, Sh. Navneeraj Sharma and Sh. Rishabh Roshan.

(Ajay Kumar Saxena)
Chief Engg., CERC

(Ravinder Gupta)
Director (SP&PA), CEA

(Kapil Dev)
AVP, PXIL

(Akhilesh Awasthy)
Director, IEX

(Ravinder)
Former Member, CEA

(Dr. Sushanta Chatterjee)
Joint Chief (RA), CERC
Member Secretary

(S K Soonee)
CEO POSOCO
Chairperson

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I	CERC order Dated 30.04.2015 in Petition No. 158/MP/2013 in the matter of Petition under Regulation 63 and 64 of CERC (Power Market) Regulations, 2010 for removal of difficulty arising due to present method of Transmission Corridor allocation to Power Exchanges for Collective Transactions
II	CERC order dated 6th February, 2007 on guidelines for grant of permission for setting up and operation of Power Exchange
III	Letter to Secretary, CERC by POWERGRID dated 18th September, 2008 on Congestion Management in Multi Exchange Scenario
IV	Letter to Executive Director, SO, POWERGRID from Secretary, CERC dated 14th October,2008, on Approval to PXI to start Operations and pro rata allocation for allocation of transmission capacity to Power Exchanges
V	Gist of Discussions Held Between NLDC, IEX and PXI on 16th October 2008 to discuss the issue of congestion management
VI	Presentation by Power Market Division of CERC on present methodology of transmission corridor
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IX	Presentations by M/s Power Exchange India Limited (PXIL)
X	Presentation by Dr. Nicholas Ryan on allocation of transmission corridor for social welfare maximization in the Indian power market
XI	Study on Simulation of Alternatives Proposed for Allocation of Transmission Corridor between Power Exchanges

References of Literature Survey

S. No	Title of the Paper/Document/Article	Author/Group/Copyright Holder	Year of Publication
1	Working Paper on Congestion management and power exchanges: their significance for a liberalised electricity market and their mutual dependence	François Boisseleau and Laurens de Vries, Delft University of Technology	2001
2	"Electricity Market Design: The Good, the Bad, and the Ugly" published in the proceedings of the Hawaii International Conference on System Sciences	Peter Cramton, University of Maryland	2003
3	Report of Joint Working Group C2/C5-05 titled" Congestion Management: The System Operators Challenge to Balance Transmission Transfer Capacity with an Acceptable Security Level"	Ole Gjerde, Juan Bogas, Al DiCaprio, Olav Bjarte Fosso, Saulo Cisneiros, Maarit Uusitalo - On behalf of: JWG C2/C5-05: Development and Changes in the Business of System Operators	2005
4	CIGRE Technical brochure TB-301 titled" Congestion Management in Liberalized Market Environment"	Working Group C5.04	2006
5	ETSO interim report , 2008 " Development and implementation of a Coordinated Model for Regional and Inter-regional Congestion Management	ETSO, EUROPEX	2008
6	"Multiple Power Exchanges In India – A Case Study" CIGRE 2010, C5 Committee paper	S.K. Soonee, S.S. Barpanda, M.K. Agrawal, S.C. Saxena from NLDC, Powergrid Corporation of India Ltd	2010
7	Business Rules Of Indian Energy Exchange Limited(IEX)	IEX	2012
8	EUPHEMIA Public Description – PCR Market Coupling Algorithm version 0.6	APX – Belpex – EPEX Spot -Mercatoelettrico (GME)- Nord Pool Spot - OMIE OTE (PCR PXs)	2013
9	Overview of Cross-Border Trading In Central West Europe	L. Gyselen, C. De Jonghe and R. Belmans from KU Leuven, Electrical Engineering Department ESAT–ELECTA / EnergyVille, Belgium	

Expert Group on Transmission Corridor Allocation to Power Exchanges for Collective Transactions

Expert Group Members

1. Shri S K Soonee, CEO POSOCO-Chairperson
2. Shri Ajay Kumar Saxena, Chief (Engg.), CERC
3. Shri Ravinder Gupta, Director (SP&PA), CEA
4. Shri Ravinder, Former Member, CEA
5. Shri Kapil Dev, AVP (Business Development), PXIL
6. Shri Akhilesh Awasthy, Director (Operations), IEX
7. Dr. Sushanta Chatterjee, Joint Chief (RA), CERC-Member Secretary

Co – Opted members

1. Prof. Abhijit R. Abhyankar, IIT Delhi
2. Dr. Puneet Chitkara, Consultant, KPMG

Special Invitees:-

Dr. Nicholas Ryan, Associate Professor, Yale University

1. Executive Summary

Central Electricity Regulatory Commission (CERC) issued guidelines in February, 2007 for setting up and operation of power exchanges in pursuance of its statutory responsibilities of developing market for electricity. Multiple power exchanges at the national level were envisaged to encourage competition. CERC allowed operational freedom to the power exchanges within an overall regulatory framework. Hon'ble Commission while granting permission to the power exchanges, recognized the issue of transmission corridor allocation in a multi-exchange scenario. CERC advised the power exchanges and NLDC to discuss the matter of Congestion in Multi Exchange scenario with a view to evolve an agreeable and optimal solution. The matter was discussed in the meeting held between NLDC and both Power Exchanges on 16th October, 2008. Allocation of transmission corridor between Power Exchanges on pro-rata basis was agreed to by both Power Exchanges in this meeting. There it was also observed that pro-rata allocation is sub-optimal solution.

CERC (Power Market) Regulations, 2010 provide the regulatory framework regarding functioning of Power Exchanges. Clause 32(iii)(b) of the Power Market Regulations, 2010 regarding the delivery procedure mentions that the Procedure for scheduling of Collective Transactions may cover the aspect of Sharing of available transmission margins between multiple Power Exchanges.

Power Exchange India Limited (PXIL) under Regulation 63 & 64 of the Central Electricity Regulatory Commission (Power Market) Regulations, 2010 filed a petition with CERC seeking changes in the present system of transmission corridor allocation for collective transactions undertaken through multiple power exchanges. PXIL submitted that present method of pro-rata allocation has many operational issues and is detrimental for sustenance of smaller exchanges. PXIL also proposed that a fixed amount of corridor may be allocated between the operating exchanges along with a caveat that if that particular exchange is not able to use the allocated corridor, then the other exchange will have the right to use the residual corridor. CERC in its Order dated 30th April, 2015 referred the matter to an Expert Group.

The terms of reference of the Expert group are to review the present transmission corridor allocation methodology between power exchanges, examine and deliberate merits and demerits of various methodologies and finally suggest viable methodologies for allocation of transmission corridor that ensures social welfare maximization considering practical aspects of implementation of the suggested methodologies.

The Expert Group deliberated on the pros and cons of various transmission corridor allocation methodologies. The discussions are summarized below:

i. Co-relation between change in cleared volumes on the power exchanges and the present transmission corridor allocation methodology is indirect in nature and therefore, could neither be ruled out nor established..

ii. The present transmission corridor allocation methodology impacts the ability to clear and schedule trades. But the impact on viability of the operation of power exchanges could not be firmly established.

iii. With reference to the current pro-rata methodology, it was agreed that it is not an optimal solution. Nonetheless, it was an informed decision like introduction of multiple power exchanges in a single day ahead physical delivery market.

iv. The various allocation methods like pro-rata allocation, priority based rules, explicit auctions were discussed and found to be sub-optimal in comparison to the solution obtained by merging of bids. The merits and demerits of these methods as per the technical literature and Hon'ble Commission Order dated 30th April, 2015 were discussed.

v. With reference to the solution suggested by PXIL in the Petition before CERC, i.e. allocation of corridor on equal basis (50:50), it was agreed that the methodology suggested was ad-hoc, sub-optimal and would amount to a pro-rata solution only. Further, this would lead to an iterative process if residual margins after the first round are to be utilized. It needs to be appreciated that "Equity" is different from "Equality".

vi. A study on "Simulation of Alternatives Proposed for allocation of Transmission Corridor between Power Exchanges" was carried out. The present models were tested on a 14 bus system with normal bids and considering only congestion on one corridor. The study tries to show how merging of bids of both power exchanges would be the first best solution in comparison to various other allocation methods. The proposed four mathematical models provide a feasible solution under the constraint of maintaining the Power Exchange identities separate. However, the model results also indicate that the above solution could be further improved by relaxing this constraints and by merging the bids. It was also found that further work would be required on the proposed models by explicitly incorporating block bids.

vii. Merging of the bids from the Power Exchanges, apart from being not acceptable to the present Power Exchanges, would require change in the market design and amendment in the CERC Power Market Regulations in addition to resolution of the various practical considerations such as confidentiality, combined solution, logistics, settlement among multiple exchanges, etc. Regarding merging of the Power Exchanges, worldwide there is a single Power Exchange in a single physical delivery market. Internationally, Power Exchanges in different geographies have a different market structure and cooperate voluntarily through Market Coupling. The various issues expressed by the Power Exchanges associated with merging of the bids are as follows:

- It is a basic change in the existing philosophy of the market structure in respect of the functioning of power exchanges
- The distinctive identity of the Exchanges would be compromised.
- Price discovery is the core function of the Power Exchanges
- A large number of exchanges could mushroom, and reliability and credibility of exchange as a dependable institution for power trading may be eroded.
- In the Indian context, social welfare maximisation involves a whole gamut of larger issues and is not limited to only the Power Exchanges
- There were different views on the creation of an independent price discovery mechanism in a 'super exchange'. It was apprehended that such an arrangement could become a road block in product innovation and technology up gradation by

virtue of the fact that a super body, having no stake in profit or loss, would have no motivation to constantly improve and innovate.

After detailed deliberations, the recommendations of the Expert Group are as follows:

1.1. The solution obtained by merging the bids/market coupling of the two power exchanges would give the optimum solution with social welfare maximisation, in this market segment, irrespective of congestion. This would require amendment in the CERC Power Market Regulations and basic market structure in addition to resolution of the various other practical considerations such as confidentiality, running of merging solution, logistics, settlement among multiple exchanges, etc.

1.2. All other methods excluding those based on merging of bids lead to a solution which may be optimal in a given set of conditions only.

1.3. The present method has been implemented with the direction of the Hon'ble Commission and agreed between NLDC, IEX and PXIL in October 2008. Hence, for the present, the existing method of allocation of transmission corridor based on pro-rata allocation may be continued with the modification as suggested below.

1.4. A priority allocation of corridor upto 15% on constrained corridors to the smaller Power Exchange may be made (If there are only two Power Exchanges functioning, then the Power Exchange with a market share less than 20% is considered the smaller Power Exchange). To start with Requisition upto 10% by the smaller Power Exchange on a constrained corridor would be allocated corridor on priority and the balance would be shared as per the existing pro-rata methodology. On the un-congested transmission corridors, no priority allocation is necessary to the smaller Power Exchange and it would continue as per the existing methodology based on pro-rata and the same will also be reviewed after six months.

1.5. The methodology suggested above may be tried on a pilot basis for a period of 6 months and both Power Exchanges and NLDC shall submit a report covering various aspects such as unconstrained cleared volumes, trade volumes, prices, demand made on corridor, corridor utilization, impact of priority allocation of corridor to the smaller

Power Exchange on market participation, etc. Based on the experience gained, the methodology of sharing of transmission margins may be reviewed by the Commission.

1.6. The Expert Group would like to place on record a word of caution regarding allocation of transmission corridor in case of congestion. Introduction of priority allocation in transmission is not a sustainable solution and the present proposal is being recommended only as an interim measure keeping in view the need for facilitating existence of multiple Power Exchanges.

1.7. The optimal solution for allocation of transmission corridor to power exchanges in case of congestion could be obtained by merging of bids/market coupling method. A separate committee for long term solution may look into the market design issues in a holistic manner including the transmission access methodology besides requirement of infrastructure, logistics, settlement etc. for implementation of merging of bids for optimal solution of transmission corridor allocation amongst multiple exchanges.

2. Introduction

Power Exchange India Limited (PXIL) under Regulation 63 & 64 of the Central Electricity Regulatory Commission (Power Market) Regulations, 2010 filed a petition before CERC seeking changes in the present system of transmission corridor allocation for collective transactions undertaken through the power exchanges. PXIL submitted that present method of pro-rata allocation has many operational issues and is detrimental for sustenance of smaller Power Exchanges. PXIL also proposed that a fixed amount of corridor may be allocated between the operating exchanges along with a caveat that if that particular exchange is not able to use the allocated corridor, then the other exchange may use the residual corridor. Essentially, PXIL demanded equal right on the corridor without compromising the utilization of the scarce resource.

Hon'ble Commission heard the submissions of PXIL, POSOCO, IEX and IIT Bombay and decided that the entire matter of transmission corridor allocation should be examined by an Expert Group so as to find out a solution which will not only be acceptable to both power exchanges but also achieve social welfare maximization. The order of the Commission is at Annexure-I. Hon'ble Commission vide para (14) of its order dated 30.04.2015 in Petition No. 158/MP/2013 has constituted an Expert Group as follows:-

Sr. No.	Member of the Expert Group	Remarks
1.	**Shri. S. K. Soonee, CEO, POSOCO**	Chairperson
2.	**Shri Ajay Kumar Saxena, Chief (Engg.), CERC**	Power System Expert
3.	One person at the level of Chief Engineer to be nominated by CEA	**Shri Ravinder Gupta**, Director (SP&PA) has been nominated by CEA as Power System Planning Expert
4.	Special Invitee	**Shri Ravinder**, Former Member (PS), CEA
5.	Power Market Expert	**Dr. Puneet Chitkara**, Consultant, KPMG co-opted as Power

		Market Expert
6,	One Representative each from IEX and PXIL having knowledge and experience in Operational matters	**Shri Kapil Dev**, AVP(Business Development), PXIL **Shri Akhilesh Awasthy**, Director (Operations), IEX
7	Any other expert from reputed Academic Institution/Research Institute as Special Invitee	**Prof. Dr. Abhijit R. Abhyankar**, IIT Delhi was co-opted by the Expert Group
8	**Dr. S. K. Chatterjee, Jt. Chief (RA), CERC**	Member Secretary

3. Terms of Reference

The Para (15) of the Order defines the Terms of Reference and scope of work of the Expert Group as under:

a) Review the present transmission corridor allocation methodology between power exchanges in the light of its implementation since 2009, its co-relation with the behavior of market participants in the exchanges and its impact on the viable operations of the exchanges and merits and demerits of continuation of the existing system of corridor allocation;

b) Examine and deliberate on the merits and demerits of the methodology suggested by PXIL, the methodology suggested by IEX, the methodology suggested by NLDC vide its letter dated 18.9.2008 and the Min–Max fairness theory with proportionate regret as suggested by Prof. Soman in the light of the experience gained during the past five years and the best international practices suitable to Indian conditions as the Expert Group considers appropriate;

c) Suggest viable methodologies for allocation of transmission corridor that ensures social welfare maximization along with optimal corridor utilization, with deliberations on the practical aspects of implementation of the suggested methodologies.

4. Background of Multiple Power Exchanges in India

4.1. Central Electricity Regulatory Commission (CERC) in pursuance of its statutory responsibilities of developing market for electricity vide order dated 6th February, 2007 **(**Copy enclosed as Annexure-II) issued guidelines for grant of permission for setting up and operation of Power Exchange in India. Multiple Power Exchanges at the National level were envisaged to encourage competition amongst Exchanges. CERC allowed operational freedom to the Power Exchange within an overall regulatory framework. Hon'ble Commission while granting permission to the Power Exchanges, recognized the issue of transmission corridor allocation in a multi-Exchange scenario.

4.2. POWERGRID in its letter dated 18th September, 2008 to Secretary, CERC (copy enclosed as Annexure-III) highlighted the issue of Congestion Management in Multi Exchange scenario. The various options available for allocation of transmission corridor between multiple Power Exchanges like Priority based rules, Pro-rata, Explicit Auctioning and merging of the bids obtained by each Power Exchange and finding a fresh solution honouring the constraints were deliberated.

4.3. Secretary, CERC vide letter dated 14th October, 2008(Copy Enclosed as Annexure-IV) directed NLDC to use pro-rata methodology based on the requisition by respective Exchanges to allocate transmission corridor between the Power Exchanges. CERC also advised the Power Exchanges and NLDC to discuss the matter of Congestion in Multi Exchange scenario with a view to evolve an agreeable and optimal solution. The issue was discussed in a meeting held between NLDC, IEX and PXI on 16th October, 2008 (Gist of Discussions enclosed as Annexure-V) and it was decided to begin with pro-rata allocation of transmission corridor based on volumes.

5. Deliberations of the Expert Group

The Expert Group held multiple meetings to deliberate on the issues. The summary of the deliberations held during these meetings are as detailed below:

5.1. Power Market Division of CERC made a presentation (copy enclosed as Annexure-VI) on present method being followed for allocation of transmission corridors to different power exchanges for Collective transactions. During the deliberations the brief background on basic principle for adopting the current method for allocation of transmission corridor to power exchanges for collective transactions was discussed. The present method was designed considering that the prices must not be disclosed to NLDC and the method shall not be iterative in nature. Only one round of iteration would be performed after receipt of the unconstrained market solution. Any new solution which is proposed should also meet these basic principles considering the practical aspects of implementation.

5.2. During the first meeting of the Expert Group, the prices in Regions of S1 and S2, Rest of India and Market Clearing Prices in both the exchanges after the introduction of current transmission corridor allocation methodology by NLDC in August, 2009 were discussed by the Expert group (Presentation attached at Annexure-VII). It was decided that the volume cleared corresponding to different prices should also be studied in the next meeting for better clarity.

5.3. In order to establish any correlation between the behavior of market participants on their bidding pattern and to study if there is any impact on viability of power exchanges due to present methodology of allocation of transmission corridors to power exchanges, Expert Group advised the representatives of both Power Exchanges to make a presentation.

5.4. As suggested by the Chairman of the Expert Group, a comprehensive literature survey was carried out on the issue of congestion management and transmission corridor allocation and circulated to all members of the Expert Group by Power Market Division of CERC. Literature survey is enclosed as Volume –II of the report.

5.5. Representative member from M/s IEX made a detailed presentation during the second meeting of the Expert Group (Enclosed as Annexure – VIII) The presentation included the

Average Clearing Volume (ACV) and Average Clearing Price (ACP)of the two exchanges for three different time phases, starting from the date of commencement of operation of both power exchanges till date. The three phases identified were Phase – I (June, 2008 to Dec 2009), Phase – II (Jan, 2010 to Mar, 2012) and Phase – III (April, 2012 till date). It is also pertinent to mention that Phase – III represents the period when the bidding in the Power Exchanges was shifted from hourly to sub-hourly (15-minute) basis.

5.6. It was observed from the data for the three phases that the prices were converging in both the exchanges when the market share of both the power exchanges was significant during the first two phases. Congestion was observed mainly on one corridor i.e., Southern Region vs. Rest of India. During some periods in the second phase, the volumes in PXIL towards SR were significant and touched about 1/3rd of that in IEX. It was observed that even for the period when there was nil corridor availability for power transfer towards Southern Region (post synchronization of NEW and SR grids on 31st Dec, 2013), the volume cleared in both the exchanges were following a similar trend. From this, it may be inferred that the methodology of allocation of transmission corridor has no co-relation with the volume cleared and the prices discovered..

5.7. Further, it was observed that the market clearing volume and prices discovered in both the Power Exchanges (IEX and PXIL) started diverging towards the end of the second phase. The reasons for this were not very clear and need to be looked into separately.

5.8. Representative member from M/s PXIL made a detailed presentation in this regard in the third meeting of the Expert Group. [Copy enclosed as Annexure IX]. The growth in annual traded volumes of PXIL, IEX, trend of curtailment were analysed based on UMCV, MCV, UMCP, Congestion, Bid Volume and Bid Price of PXIL client in Western Region, Southern Region and Northern Region were presented and discussed. From the presentations of M/s PXIL also any co-relation between the bidding pattern and impact on viability of power exchanges due to present methodology of allocation of transmission corridors to power exchanges could not be firmly and directly established.

5.9. In addition to the methodologies already discussed, i.e., pro-rata allocation and priority based rules, the following other methods were also debated:

- *50:50 allocations between the two exchanges before the bidding period:*
  This is clearly suboptimal and would lead to increase in iterations in implementation.
- *Explicit auctioning of transmission corridor:*
  It was deliberated that given the fact that the Indian Power System is a meshed network, and congestion is a shifting phenomenon, explicit auctioning of the transmission corridor is very complex and difficult to implement.
- *Merging the bids of two power exchanges:*
  This was deliberated and is considered to be an optimal solution. Internationally, this is being done in UK, which has two Power Exchanges, namely, N2EX and APX. Implementation issues such as confidentiality, running of one Super Exchange, establishment of full-fledged logistics, power exchange software, settlement among multiple exchange, etc. needs to be resolved before this merging of bids can be implemented. The concept of merging bids of the two Power Exchanges needs further deliberations also.

5.10. A methodology was suggested by Dr. Abhyankar for corridor allocation among the two power exchanges where the two power exchanges share the masked bid data with a common agency i.e. NLDC. Then, NLDC after optimizing for the transmission corridor allocation based on the output obtained by merging the bid data submitted by the two power exchanges, informs the two exchanges of the margins available to them. Then the power exchanges can go ahead with the final price calculations. After deliberations, it emerged that the proposal may require matching of buy/sell bids of one power exchange with sell/buy bids of other power exchange. Expert Group requested Dr. Puneet Chitkara and Dr. Abhyankar for making a comprehensive study for transmission corridor allocation based on mathematical modelling with an objective function of maximizing social welfare.

5.11. Dr. Nicholas Ryan, Special invitee of the Expert Group, through video conferencing presented his views on allocation of transmission corridor for social welfare maximization in the Indian power market (Copy of presentation enclosed at Annexure-X). He stressed on the point that the advantages of market coupling or integration for maximizing social welfare will be more if the market share of both the power exchanges is significant. In the present Indian Market condition, the benefits would be much less considering the fact that share of one exchange is quite less compared to other.

5.12. A study on “Simulation of Alternatives Proposed for allocation of Transmission Corridor between Power Exchanges” was carried out by Dr. Puneet Chitkara and Dr. Abhyankar [Copy of the report enclosed as Annexure-XI]. They have proposed four mathematical models namely SUP, SEN, DWL and TPM. The SUP and SEN models are based on superposition principle with an objective to maximize social welfare whereas DWL method objective is to minimize change in unconstrained social welfare. The TPM model is based on the concept of general transportation problem. In their report they had made a comparative analysis of various methods based on mathematical modelling, proposal by PXIL and merging of the bids of the both exchanges and the current practice. The simulation was carried out considering a 14 bus system and some hypothetical bid data. From the study carried out, it emerges that merging of bids of both power exchanges would be optimal solution. Dr. Puneet Chitkara and Prof. A R Abhyankar were also of the view that the proposed four mathematical models provide a good solution and also satisfy the constraint of maintaining the Power Exchange identities separate.

5.13. The TOR for the Expert Group mentions the core issue that is to be discussed is the allocation of transmission corridor between multiple Power Exchanges in case of congestion. However, the Expert Group opined that the larger issue of implementation of multiple Power Exchanges itself is sub-optimal and is not part of the TOR. Further, irrespective of congestion, merging of bids collected through multiple Power Exchanges would result in an overall optimization and maximization of social welfare. This would require changes in the market design and amendment in the CERC Power Market Regulations in addition to resolution of the various other practical considerations such as confidentiality, running of one Super Exchange, establishment of full-fledged logistics, power exchange software, settlement among multiple exchanges, etc.

5.14. Sh. Ravinder expressed his concern that South Asia Sub-regional Economic Cooperation (SASEC) has three (3) priority areas of cooperation viz. Transport, Trade facilitation and

Energy. SASEC grid is almost a reality now. He opined that single price signal from merging of bids of two Power Exchanges would align with the vision of SASEC which is to improve energy access and security in the region by developing essential infrastructure, and promoting intraregional power trade to reduce costs and import dependence. The issues associated with merging of bids were deliberated.

5.15. During the deliberations, it emerged that the merging of bids or market coupling method implementation is practically having only one Power Exchange, as price discovery is the core function of any Power Exchange. Before taking any decision on this method, first the issue of choice between having a single power exchange or multiple power exchanges needs to be addressed. Introduction of multiple power exchanges, though a sub-optimal solution, has been a well debated and conscious choice in India.

5.16. Subsequent to the above deliberations, it was decided to finalize the Expert Group Recommendations based on the above and a draft was circulated. However, both Power Exchanges and co-opted members disagreed on the recommendations and there was a need for a common meeting ground in regard to the sharing of congested transmission corridors which was acceptable to both Power Exchanges. Accordingly, a meeting was held on the 10th December 2015 where both Power Exchanges presented their view points and deliberations held are as given below.

5.17. The concerns raised by Prof. AR Abhyankar and Dr. Puneet Chitkara were discussed in detail (methodology suggested by them is deliberated in Para 5.12 above). The methodology adopted in this study uses a 'test 14 bus system' and more in-depth study is required to capture full complexity such as loop flows, counter flows, etc. is required.

5.18. Concerns of IEX raised in their communication dated 6th Nov 2015 were discussed. IEX mentioned that the Hon'ble Commission has taken a conscious decision to have multiple Power Exchanges in the same geographical area and there is no requirement to change the current market design. IEX opined that the methodology suggested by Prof. AR Abhyankar and Dr. Puneet Chitkara also needs to be considered. IEX opined that change in market design is not in the purview of the Expert Group and merging of bids has its own issues. IEX also elaborated some aspects of Market Design in Europe and also opposed merging of bids.

5.19. Concerns of PXIL raised in their communication dated 13th Nov 2015 were discussed. PXIL are of the opinion that correlation exists between volumes cleared in the Exchanges and corridor allocation and the viability of the Power Exchange itself is impacted by the corridor allocation philosophy, which is contrary to the earlier deliberations of the Expert Group (Para 5.6 above). PXIL further opined that status quo should not be maintained and the present methodology though agreed mutually in 2008 was only an interim measure. The allocation methodology itself was last modified in 2009 based on the operational difficulties being faced. PXIL also did not agree to the merging of bids.

5.20. From the deliberations it emerged that the idea of merging of the bids of two exchanges was not acceptable to both Power Exchanges. The main contention was that:

- It is a basic change in the existing philosophy of the market structure in respect of the functioning of power exchanges
- The distinctive identity of the Exchanges would be compromised.
- Devoid of price discovery engine, exchange would be reduced to a glorified trader
- A large number of exchanges could mushroom, and reliability and credibility of exchange as a dependable institution for power trading may be eroded.
- The committee has stretched the concept of social welfare too far ignoring the fact that the volume of power traded on the Exchanges is 3% only. In the Indian context, social welfare maximisation involves a whole gamut of larger issues.
- There were strong views on the creation of an independent price discovery mechanism in a 'super exchange'. It was apprehended that such an arrangement could become a bureaucratic road block in product innovation and technology upgradation by virtue of the fact that a super body, having no stake in profit or loss, would have no motivation to constantly improve and innovate.

5.21. The committee took cognisance of the views of the Exchanges and others and decided that in this case, a suitable methodology needs to be adopted, so that in the event of transmission constraints, the customers may find difficult in approaching the exchange with a relatively smaller market share in a pro-rata transmission allocation methodology currently being followed. The committee was not in favour of developing a sub - optimal complex algorithm involving extraction of bid details from the two exchanges. The committee concluded the deliberations by requesting Sh. Ravinder to have detailed discussion with parties in a separate meeting and try to work out a mutually acceptable methodology taking in to account the desirability of autonomous functioning, freedom to compete and the exchange with a relatively smaller market share should not face a customer bias even in a scenario of transmission constraints.

5.22. In the separate meeting held with the Power Exchanges, Sh. Ravinder underlined the importance of coordination and cooperation among the competing Exchanges with the aim of presenting a common face to the policy makers and public as transparent trading platforms, drivers of investment in power generation, thought leaders in the electricity market, developing new power and transmission service products to improve market efficiency etc. The discussions took off on a cordial note.

5.22.1. On the issue of appropriate methodology transmission capacity allocation in a constrained situation, IEX observed that the constrained scenario is essentially towards the south only. As for rest of India, there is fair competition and if one exchange has lesser volume then it's not because of flaw in transmission allocation methodology. However, IEX indicated willingness to accept priority allocation upto 5% to 10 % for the exchange with a relatively smaller market share on a constrained corridor, and balance allocation on pro-rata basis, to remove the perceived bias in customer behaviour.

5.22.2. PXIL, however, did not agree with the very idea of trying to find a way out to help the exchange with a relatively smaller market share to survive in a constrained scenario. PXIL reiterated that it was a matter of principle that when there are two exchanges, the access to transmission capacity should be in the ratio of 50:50 with unutilized capacity allotted to other exchange. Alternatively, PXIL stated that, one third capacity could be allocated and the remaining two third could be allocated pro-rata, as was proposed in the petition.

5.22.3. Sh. Ravinder, however emphasized and impressed upon the need to have a beginning. Subsequently, PXIL also agreed to priority allocation upto 15% for the Power Exchange with a relatively smaller market share on the congested corridors and pro-rata sharing of balance margins as per existing methodology, subject to review of the performance of the methodology periodically To start with the priority allocation will be upto 10%..

5.23. The Expert Group deliberated the provisions under Regulation 35 of the CERC Power Market Regulations, 2010, which is quoted below for ready reference:

35. A Power Exchange which has less than 20 % market share for continuously two financial years falling after a period of two years of commencement of its operations shall close operations or merge with an existing Power Exchange with in a period of next six months. (For this purpose Market size is defined as the total Annual Turnover in Million Units of all contracts transacted in all the Power Exchanges in each financial year)

Provided that this regulation shall not apply if there are only two Power Exchanges in operation.

As per the above provision, at least two Power Exchanges would continue to exist even if the market share of one of the Power Exchange falls below 20%. In other words, it may be inferred that the survival of the Power Exchange with a relatively smaller market share is desirable in case there are two Power Exchanges only. From the Regulation 35, it may also be inferred that in case there are two Power Exchanges only, then, if one of the Power Exchanges has a low market share, i.e., below 20% it may be considered as the smaller Power Exchanges. From the Annual Report of the Market Monitoring Cell (MMC) of CERC for the year 2014-15, it is observed that out of the total volume traded in the Power Exchanges, 96% was through IEX and 4% was through PXIL or in other words, the volume traded through PXIL is of the order of 5%.

5.24. The Expert Group took note of the "Regulatory Flexibility Act of USA" which requires federal agencies to consider the impact of regulations on small entities in developing the proposed and final regulations.

5.25. Taking into account the aspects deliberated in Paras 5.23 and 5.24 and also the fact that both Power Exchanges, to start with, are willing to accept priority allocation of transmission corridor upto 10% on constrained corridors, the Expert Group recommends the implementation of priority allocation of corridor upto 15% on constrained corridors to the smaller Power Exchange when only two Power Exchanges are functioning. To start with, requisition upto 10% by the smaller Power Exchange on a constrained corridor would be allocated corridor on priority and the balance would be shared as per the existing pro-rata methodology. On the un-congested transmission corridors, no priority allocation is necessary to the smaller Power Exchange and it would continue as per the existing methodology based on pro-rata.

The methodology will be reviewed after 6 months from its implementation date.

6. Conclusions

Based on the extensive literature survey, deliberations in various meetings, presentations by both the Power Exchanges, presentation by Dr. Nicholas Ryan, Report on Simulation of Alternatives Proposed for Allocation of Transmission Corridor between Power Exchanges and CERC (Power Market) Regulations, 2010, the Expert Group conclusions drawn in relation to the specific terms of reference and scope of work of the Expert Group are summarized below:

i. Co-relation between change in cleared volumes on the power exchanges and the present transmission corridor allocation methodology is indirect in nature and therefore, could neither be ruled out nor established.

ii. The present transmission corridor allocation methodology impacts the ability to clear and schedule trades. But the impact on viability of the operation of power exchanges could not be firmly established.

iii. With reference to the current pro-rata methodology, it was agreed that it is a sub-optimal solution. Nonetheless, it was an informed decision like introduction of multiple power exchanges in a single day ahead physical delivery market.

iv. The various allocation methods like pro-rata allocation, priority based rules, explicit auctions were discussed and found to be sub-optimal in comparison to the solution obtained by merging of bids. The merits and demerits of these methods as per the technical literature and Hon'ble Commission Order dated 30th April, 2015 were discussed.

v. With reference to the solution suggested by PXIL in the Petition before CERC, i.e. allocation of corridor on equal basis (50:50), it was agreed that the methodology suggested was ad-hoc, sub-optimal and would amount to a pro-rata solution only. Further, this would lead to an iterative process if residual margins after the first round are to be utilized.

vi. A study on "Simulation of Alternatives Proposed for allocation of Transmission Corridor between Power Exchanges" was carried out. The present models were tested on a 14 bus system with normal bids and considering only congestion on one corridor. The study tries to show how merging of bids of both power exchanges would be the first best solution in comparison to various other allocation methods. The proposed four mathematical models provide a good solution and also satisfy the constraint of maintaining the Power Exchange identities separate. The methodology adopted in this study uses a 'test 14 bus system' and more in-depth study is required to capture full complexity such as loop flows, counter flows, etc. is required.

vii. Merging of the bids from the Power Exchanges, apart from being not acceptable to the present Power Exchanges, would require changes in the market design and amendment in the CERC Power Market Regulations in addition to resolution of the various practical considerations such as confidentiality, running of merging solution, logistics, settlement among multiple exchanges, etc. In case the same is implemented, the power exchanges would compete on services they offer rather than the price discovered by them in Day Ahead Market (DAM).

7. Recommendations of the Expert Group

The recommendations of the Expert Group are as follows:

7.1. The solution obtained by merging the bids/market coupling of the two power exchanges would give the optimum solution with social welfare maximisation, in this segment, irrespective of congestion. This would require changes in the market design and amendment in the CERC Power Market Regulations in addition to resolution of the various other practical considerations such as confidentiality, running of merging solution, logistics, settlement among multiple exchanges, etc.

7.2. All other methods excluding those based on merging of bids lead to a solution which may be optimal in a given set of conditions only.

7.3. The present method has been implemented with the direction of the Hon'ble Commission and agreed between NLDC, IEX and PXIL in October 2008. Hence, for the present, the existing method of allocation of transmission corridor based on pro-rata allocation may be continued with the modification as suggested in para 7.4 below.

7.4. A priority allocation of corridor upto 15% on constrained corridors to the smaller Power Exchange may be made when only two Power Exchanges are functioning (If there are only two Power Exchanges functioning, then the Power Exchange with a market share less than 20% is considered the smaller Power Exchange). To start with, Requisition upto 10% by the smaller Power Exchange on a constrained corridor would be allocated corridor on priority and the balance would be shared as per the existing pro-rata methodology. On the un-congested transmission corridors, no priority allocation is necessary to the smaller Power Exchange and it would continue as per the existing methodology based on pro-rata.

7.5. The methodology suggested in para 7.4 above may be tried on a pilot basis for a period of 6 months and both Power Exchanges and NLDC shall submit a report covering various aspects such as trade volumes, prices, impact of priority allocation of corridor to the smaller Power Exchange on market participation, etc. Based on the experience gained, the priority allocation for sharing of transmission corridors may be reviewed by the Commission.

7.6. The Expert Group would like to place on record a word of caution regarding allocation of transmission corridor in case of congestion. The core underlying issue is pertaining to “competition for the market” and “competition in the market”. From a Regulatory perspective, equity and fairness needs to ensure competition in the market as the current methodology is inclined towards competition for the market.

7.7. The optimal solution for allocation of transmission corridor to power exchanges in case of congestion could be obtained by merging of bids/market coupling method. A separate committee for long term solution may look into the market design issues in a holistic manner including the transmission access methodology besides requirement of infrastructure, logistics, settlement etc. for implementation of merging of bids for optimal solution of transmission corridor allocation amongst multiple exchanges.

Public Hearing on the Draft CERC Power Market Regulations 2020

Suggestions on behalf of RLDCs/NLDC
Power System Operation Corporation Ltd.
14th August 2020

Draft CERC Power Market Regulations 2020 (PMR 2020)

- A Welcome Step
- CERC order on Petition No. 155/2006 (Suo motu) regarding Guidelines for the grant of permission for setting up and operation of Power Exchange dated 06th February 2007 states as follows:

  "20. The general approach of the Commission is to allow operational freedom to the PX within an overall framework. The ***regulation would be minimal*** *and restricted to requirements essential for preventing derailment/accidents and collusion. Private entrepreneurship would be allowed to play its role. The Commission shall keep away from governance of PX, which would be required to add value and provide quality service to the customers."*

A Paradigm Shift from the earlier CERC Power Market Regulations 2010

Objective of Power Exchange

- Proposal in Draft PMR, 2020

Objectives of Power Exchange

"The Power Exchanges shall be established and operated with the following objectives:

(1) To design electricity contracts and facilitate transactions of such contracts;
(2) To facilitate extensive, quick and efficient price discovery and dissemination."

- **Power Market Regulations, 2010:**

"10. A Power Exchange shall function with the following objectives:-

*(i) Ensure **fair, neutral**, efficient and **robust** price discovery*

(ii) Provide extensive and quick price dissemination

*(iii) Design **standardised contracts** and work towards **increasing liquidity** in such contracts*

Explanation: Liquidity is a measure of ease of entering or exiting into a transaction (generally large transaction) with minimal impact in the market price of the transacted contract."

Principles of Price Discovery

Power Market Regulations, 2010

11. A Power Exchange shall adopt the following market design in case of day ahead markets:-

A. Price Discovery

(i) The economic principle of social welfare maximisation and to create buyer and seller surplus simultaneously during price discovery.

(ii) The bidding mechanism shall be double sided closed bid auction on a day ahead basis.

(iii) The price discovered for the unconstrained market shall be a uniform market clearing price for all buyers and sellers who are cleared

(iv) In case of congestion in transmission corridor, market splitting mechanism shall be adopted.

(v) The delivery / drawl of power shall be considered at the regional periphery.

(Draft) Power Market Regulations, 2020

5. **Contracts transacted on Power Exchanges**

(1) **Day Ahead Contracts and Real-time Contracts**

(a) **Price discovery:**

(i) Price Discovery shall be done by Power Exchanges or by Market Coupling Operator, as and when notified by the Commission.

(ii) Price discovery mechanism shall adopt the principle of maximisation of economic surplus (sum of buyer surplus and seller surplus), taking into account all bid types.

(iii) The bidding mechanism shall be double sided closed bid auction on day ahead basis or on real time basis, as the case may be.

(iv) The price discovered for the unconstrained market shall be a uniform market clearing price for all buyers and sellers who are cleared:

Provided that in case of congestion in transmission corridor, market splitting shall be adopted.

- “Social Welfare Maximization” changed to “maximization of economic surplus”
- Imperative for change may be shared in the SOR

Demutualization

Proposal in Draft PMR, 2020

Part 4, Clause 9: Eligibility criteria, one of the criteria for applicants to setup power exchange is as follows:

*(2) The applicant is demutualized; for the purposes of this sub-regulation, the term "demutualized" means that the **ownership and management** of the applicant is segregated from the trading rights, in terms of these regulations*.

Suggestion:

*(2) The applicant is demutualized; for the purposes of this sub-regulation, the term "demutualized" means that the **ownership, management and participation** of the applicant is segregated ~~from the trading rights~~, in terms of these regulations*.

Market Coupling: Expert Group on Transmission Corridor Allocation between Power Exchanges (1)

- Constituted vide CERC Order dated 30th April 2015 in Petition No. 158/MP/2013 comprising of CERC Staff, POSOCO, CEA, IEX, PXIL, Independent Market Experts and Academia
- CERC Order dated 4th April 2016 on the Report submitted by Expert Group

Extracts

"The recommendations of the Expert Group Are as follows:

7.1 The solution obtained by ***merging the bids/market coupling of the two power exchanges would give the optimum solution with social welfare maximization****, in this segment, irrespective of congestion. This would* ***require changes*** *in the market design and amendment in the CERC Power Market Regulations in addition to resolution of the various other practical considerations such as confidentiality, running of merging solutions, logistics, settlement among multiple exchanges etc."*

Market Coupling: Expert Group on Transmission Corridor Allocation between Power Exchanges (2)

Extracts

"The recommendations of the Expert Group Are as follows:

*7.6 The Export Group would like to place on record a word of caution regarding allocation of transmission corridor in case of congestion. The core underlying issue is pertaining to **"competition for the market"** and **"competition in the market".** From a Regulatory perspective, equity and fairness needs to ensure competition in the market as the current methodology is inclined towards competition for the market.*

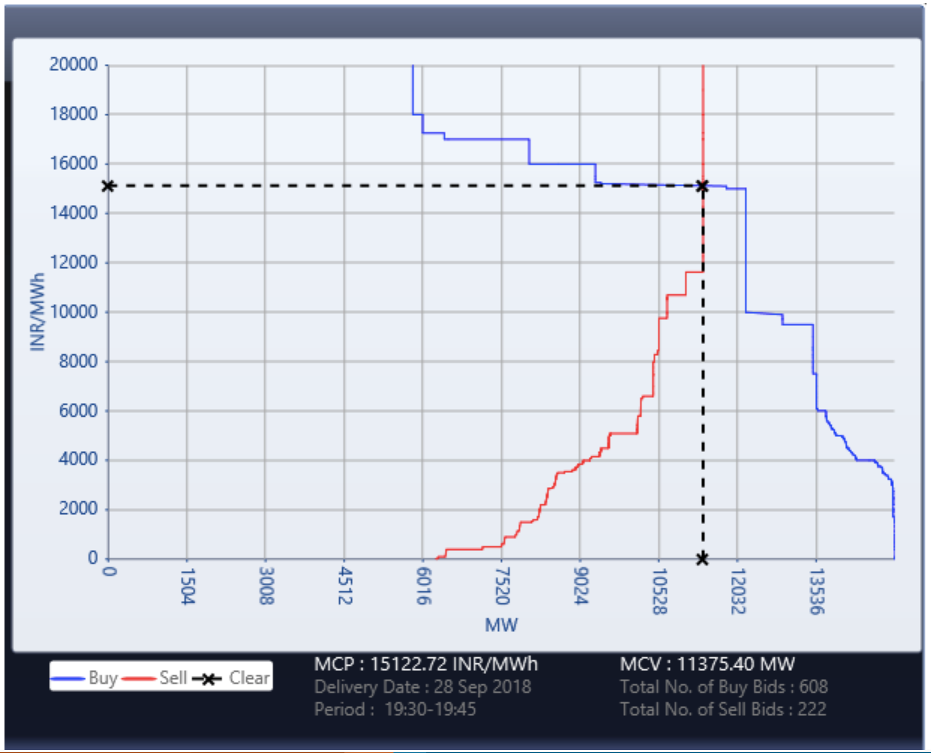
*7.7 The optimal solution for allocation of transmission corridor to power exchanges in case of congestion could be obtained by merging of bids/market coupling method. A **separate committee for long term solution** may look into the market design issues in a holistic manner including the transmission access methodology besides requirement of infrastructure, logistics, settlements etc. for implementation of merging of bids for optimal solution of transmission corridor allocation amongst multiple exchanges"*

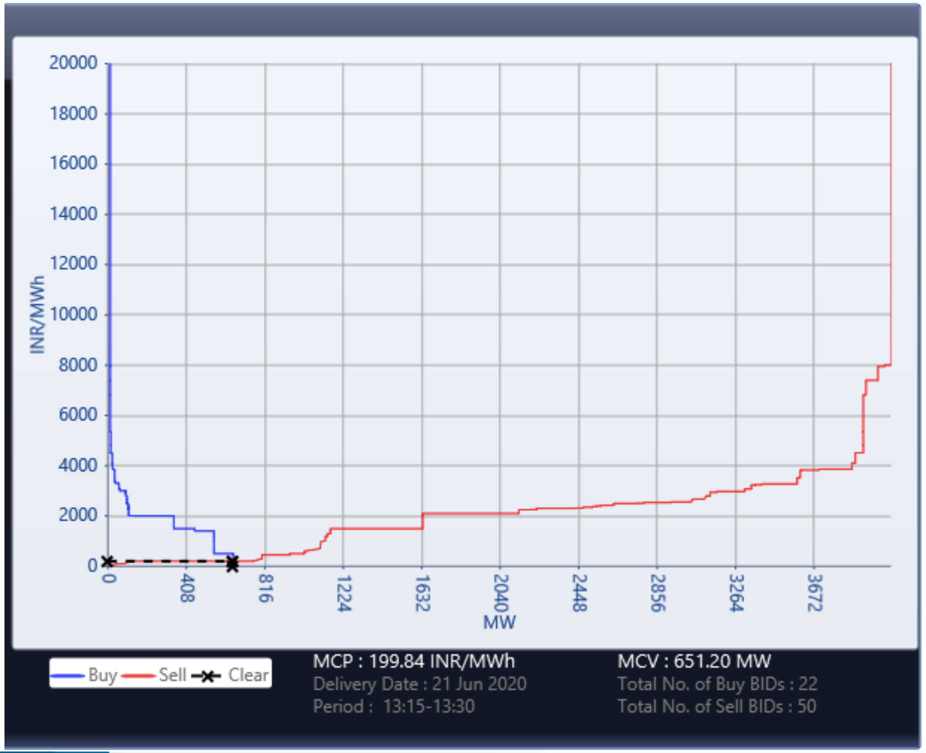
Market Coupling

- A forward looking step which will facilitate better utilization of transmission in case of congestion
- Pan-European Hybrid Electricity Market Integration Algorithm (EUPHEMIA) implemented in Europe since 2014
- India, unlike Europe, is a single physical delivery market – ”Merger of Bids”
  - Single market clearing engine
  - Uniform market clearing price
- Complex mechanism requiring harmonization of bid structures, market clearing engine, information exchange requirements, resource level constraints, system wide constraints, settlement systems, etc. – **Need for a roadmap for implementation**

Limits for Bid Prices in Power Exchanges

- **Power Exchanges free to decide the minimum and maximum prices**
- **Present limits are Max: Rs. 20 per unit and Min: Rs. 0 per unit**
- **Prime Mover: Software considerations**
- **Extrapolation of prices**
- **Internationally maximum and minimum prices decided by Regulator**





(European) Commission Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management

1. *The Harmonised Maximum Clearing Price limit proposal has to fulfil the **objective of "promoting effective competition in the generation, trading and supply of electricity"** as the limits, for day ahead have to be **set at a level that does not restrict effective competition in the generation, consumption, trading or supply in the organized wholesale market.***

2. *The Harmonised Maximum Clearing Price limit shall **take into account the value of lost load** – assumed to be the price at which TSOs take curtailment action - and as a principle be maintained at a level that shall not limit the market at times of scarcity or oversupply*

3. *The harmonised maximum clearing price for SDAC(Single Day Ahead Coupling) **shall be increased by 1,000 EUR/MWh in the event that the clearing price exceeds a value of 60 percent of the harmonised maximum clearing price for SDAC in at least one market time unit in a day** in an individual bidding zone or in multiple bidding zones*

4. *The increased harmonised maximum clearing price, set according to clause 3 **shall apply in all bidding zon**es which participate in SDAC from five weeks after the day in which the event referred to therein has taken place;*

5. *The NEMOs **shall at least every two years reassess the Harmonised Minimum and Maximum Clearing Price Limits**, and share that assessment with all market participants and review it in relevant stakeholder forums organised in accordance with CACM Regulation. A reassessment shall also follow any application of the amendment rule.*

[*http://www.nemo-committee.eu/assets/files/20170214_Harmonised%20Max-Min%20Prices%20Limit%20Proposal_Single%20Day%20Ahead%20Coupling.pdf*](http://www.nemo-committee.eu/assets/files/20170214_Harmonised%20Max-Min%20Prices%20Limit%20Proposal_Single%20Day%20Ahead%20Coupling.pdf)

Limits on Bid Prices

- In almost all the markets RES/DG despatching has drastically changed the market outcomes in the recent years.
  - The market prices can become negative e.g. Germany and Denmark with high penetration of RES/DG.
- In order to provide opportunities to storage (e.g. pumped storage, batteries etc.), there is a need to review the minimum market clearing prices going below zero.

Maximum and minimum prices

Article 3

Harmonised maximum and minimum clearing prices for SDAC

1. The harmonised maximum clearing price for SDAC shall be +3000 EUR/MWh.
2. The harmonised minimum clearing price for SDAC shall be -500 EUR/MWh.

Price Limits for Day-Ahead

https://hupx.hu/uploads/Piacösszekapcsolás/NEMO/ACER%20DA%20MAX-MIN.pdf

Maximum and minimum prices

Article 3

Harmonised maximum and minimum clearing prices for SIDC

1. The harmonised maximum clearing price for SIDC shall be +9999 EUR/MWh.
2. The harmonised minimum clearing price for SIDC shall be -9999 EUR/MWh.

Price Limits for Intra-Day

https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/ANNEXES%20NEMOs%20HMMCP%20FOR%20SINGLE%20INTRADAY%20COUPLING%20D/Annex%20I_ACER%20ID%20MAX-MIN.pdf

Block Bids (1)

- Types of Bids in the Power Exchange: Single bid, block bid (All or None type orders)
- Increasing Size of Block Bid - Power Exchanges free to modify block bid size with circulars
  - Commencement of PX operations in 2008: 10 MW,
  - 6th Dec 2008: increased to 50 MW
  - 2017: Increased to 100 MW
- Design considerations for block bids
  - Size of block bid, Duration of block bid
  - Impact of quantum and size of block bids on Market Clearing Volume, Market Clearing Price & Area Clearing Price
  - Technical minimum considerations, Scheduling, Ramping, Real time grid operations
  - Social welfare
  - Paradoxical rejection of block bids
  - Impact on smaller participants
- CERC directed examination of the impact of Block bids vide communication 6Sep 2017
  - TOR: Study impact on scheduling, transmission corridor allocation, MCP, MCV, smaller participants
  - Report submitted by POSOCO in May 2018

Block Bids (2): Extracts from the Report on Block Bids

- *"The subject of block bids and associated market design issues are complex and more study/analysis needs to be done. **Design parameters such as liquidity, concentration in the market, etc. may be considered before undertaking any change in the block bid specifications**.*

- *It was also agreed that **any change in Power Exchange Market design which has a material impact on the price discovery, volumes cleared and social welfare will need to be approved by the Hon'ble Commission***

- ***Ramping requirements in system operation need to be taken care of and any step changes should be avoided** as envisaged in the Grid Code. In future, detailed discussion on ramping restrictions on all segments of market could be taken up separately as need arises."*

Introduction of new bids

Part 4, Clause 25: Approval or Suspension of Contracts by the Commission

"…(1) The Commission may, on its own or on an application made in this behalf, permit any Power Exchange to introduce new contracts as specified in clause (1) of Regulation 4 of these regulations:

…Provided further that the Power Exchanges may introduce new bid types or modify existing bid types conforming to the types and features of the contracts ….after consultation with stakeholders and National Load Despatch Centre, under intimation to the Commission…."

- Any new bids need to be introduced with the approval of the Hon'ble Commission after due stakeholder consultations
  - Bid types & structures have an impact on Price Discovered
  - If Market Coupling or Merger of Bids is to be implemented, then harmonization of bid structures is a pre-requisite

Price Discovery Algorithm & Optimization

- PMR 2020 provides for periodic auditing of the algorithm – A welcome step

  " …..The Power Exchange shall get the algorithm audited before commencement of operations and thereafter, once in every two years and submit the findings of the audit to the Commission."

- Learnings from implementation of SCED –
  - Constraints: VC, Pmax, Pmin, Ramp Up, Ramp Down, Transmission margins
  - Single period, Multi-period
- Present Power Exchange algorithm
  - Single period matching of supply-demand curves
  - Need for multi-period optimization
  - Need to factor ramping specially in view of increasing RE penetration
- Extracts from the Report on Block Bids:

  "The problem of determining the MCP by matching the bidders to maximize social welfare is complex in many respects, particularly the inclusion of block bids with a 'All or None' characteristics make the problem a combinatorial one. ***This can be suitably addressed if the algorithm is modelled as an optimization problem with its objective function as social welfare maximization.*** *This would give flexibility to the algorithm which can be changed by adding or relaxing few constraints."*

  \- Bid Structures would need to be modified & harmonized across Power Exchanges

Information Dissemination by the Power Exchanges

- **Presently following information is made available by the Power Exchanges**
  - Prices (Area wise & total) & Volumes (Area wise & total)
  - Aggregate Sell bids & Aggregate Buy bids
  - Aggregate supply demand curves (only total)
- **Need for more information dissemination***
  - Area wise aggregated supply-demand curves
  - Total Consumer Surplus
  - Total Producer Surplus
  - Total Social Welfare
  - %age portfolios using block bids
  - Bid – Ask Spread
  - Time block wise / day-wise market concentration indices e.g., HHI (indicates level of competition)
- Information dissemination - vital for Market Monitoring

CERC Order in Petition No. SM/351/2013 dated 08/01/2014 on Improvement of Market Efficiency by information dissemination through display of Aggregate Demand and Supply Day Ahead curves by Power Exchanges on their website.

http://www.cercind.gov.in/2014/orders/SO351.pdf

** Also recommended in the Report on Block Bids, May 2018*

Thank You

Terms of Reference of Expert Group, 2015

The terms of reference and scope of work of the Expert Group were delineated in para 15 of the said order as under:

"15. The terms of reference and scope of work of the Expert Group are as under:

(a) Review the present transmission corridor allocation methodology between power exchanges in the light of its implementation since 2009, its co-relation with the behavior of market participants in the exchanges and its impact on the viable operations of the exchanges and merits and demerits of continuation of the existing system of corridor allocation;

(b) Examine and deliberate on the merits and demerits of the methodology suggested by PXIL, the methodology suggested by IEX, the methodology suggested by NLDC vide its letter dated 18.9.2008 and the Min–Max fairness theory with proportionate regret as suggested by Prof. Soman in the light of the experience gained during the past five years and the best international practices suitable to Indian conditions as the Expert Group considers appropriate;

(c) Suggest viable methodologies for allocation of transmission corridor that ensures social welfare maximization along with optimal corridor utilization, with deliberations on the practical aspects of implementation of the suggested methodologies."