Discussion Paper

on

Re-designing Ancillary Services Mechanism in India

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CERC

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Disclaimer

The issues presented in this discussion paper do not represent the views of the Central Electricity Regulatory Commission, its Chairman, or Individual Members, and are not binding on the Commission. The views are essentially of Staff of CERC and are circulated with prime aim of initiating discussions on various aspects of increasing the ambit of ancillary services in India through market mechanism and soliciting inputs of the stakeholders in this regard.

Contents

1. Introduction and Context

1.1 India's power sector is rapidly changing its characteristics with synchronization of national grid to one frequency and increase in power availability from deficient to surplus to meet system demand. The achievement of significant capacity addition from renewable energy projects in recent years and the target of integrating 175 GW of Renewables by 2022 mark India's commitment towards greener future where significant power demand in the system will be fulfilled from renewable sources.

1.2 Considering the high variability and unpredictability of generation from renewable, efficient and economical grid operation becomes one of the critical challenges in India's Power system. The Commission has taken several initiatives to ensure integration of variable RE generation. The framework for forecasting, scheduling and deviation settlement for wind and solar has been put in place. To enable thermal generators to provide balancing support, necessary regulatory framework has been provided defining technical minimum for such plants and commensurate compensation for flexing such (thermal) generation up to technical minimum. The Commission has issued Suo Motu order delineating the road map for operationalizing reserves.

1.3 Ancillary services are an indispensable part of the power system operation, which are required for improving and enhancing reliability of the power system. Ancillary Services may include a number of different operations such as frequency support, voltage support, and system restoration.

1.4 Various types of reserves, viz., primary, secondary and tertiary reserves are required to balance variable RE generation. The primary reserves have been ensured through suitable amendments in the IEGC which require the generating stations to keep such reserves for system security, by not scheduling beyond their installed capacity. For secondary control also the Commission has approved a pilot project on Automatic Generation Control (AGC).

1.5 As regards tertiary control, the Commission has issued regulations on Reserves Regulation Ancillary Services (RRAS) which have been in operation for more than a year now.

1.6 The regulations for Ancillary Services pertain specifically to balancing demand for real power with supply in real time. Balancing refers to the situation after markets have closed (gate closure) in which a System Operator acts to ensure that demand is equal to supply, in and near real time, while maintaining grid frequency at its nominal value and without compromising grid stability. To encourage the individual participants to provide these services, Ancillary Services are procured by compensating the providers of such services through a regulatory mechanism or through markets. At present, India has an administered mechanism for procurement of Ancillary Services. This discussion paper attempts to assess performance of the current framework of frequency support and balancing ancillary services mechanism in India and to suggest next generation reforms in the context by way of introduction of auction based procurement of Ancillary Services.

2. Existing Regulatory Framework for Ancillary Services in India

2.1 The Commission notified CERC (Ancillary Services Operations) Regulations (henceforth, RRAS Regulations) on 13th August, 2015. The objective of these regulations was to restore the frequency at desired level and to relieve the congestion in the transmission network. Ancillary Services that consist of either Regulation Down Service or Regulation Up Service have been defined as "Reserves Regulation Ancillary Services or RRAS". The salient features of the Ancillary Services framework are as follows:

- All the Generators, that are Regional Entities, and whose tariff for the full capacity is determined or adopted by the CERC have been mandated to provide Ancillary Services as RRAS Providers. There are approximately 67 such power plants spread across India currently. NLDC, through the RLDCs, has been designated as the Nodal Agency for Ancillary Services Operations. The Nodal Agency prepares the Merit Order Stack based on the variable cost of generation. Separate stacks are prepared for Up and Down services.
- The quantum of RRAS instruction, by the Nodal Agency, is being directly incorporated in the schedule of RRAS providers. The energy dispatched under RRAS is deemed delivered ex-bus. The deviation in schedule of the RRAS Providers, beyond the revised schedule, is being settled as per the CERC Deviation Settlement Mechanism (DSM) Regulations.
- The RRAS Energy Accounting is being done by the respective Regional Power Committee on weekly basis along with Deviation Settlement Mechanism (DSM) Account, based on interface meters data and schedule. A separate RRAS statement is being issued by RPC along with Regional DSM Account. Any post-facto revision in rates/charges by RRAS providers is not permitted.
- In case of Regulation Up, fixed charges and variable charges along with pre-specified mark-up are payable to the RRAS providers from the pool. In case of Regulation Down, 75 percent of the variable charges are payable by RRAS providers to the pool. No commitment charges are payable to the RRAS provider.

2.2 CERC, vide order dated February 29, 2016, specified the mark-up for participation in Regulation ‘Up’ as 50 paisa/kWh. The Detailed Procedures were also approved by CERC on the March 08, 2016. Ancillary Services were implemented by the Nodal Agency i.e. NLDC in coordination with RLDCs on April 12, 2016.

2.3 The present framework of Ancillary Services predominantly utilizes the thermal power stations which have ramping limitations and as such there is a need for a fast response ancillary service. Recently the Commission has also issued Suo-Motu order on pilot projects to harness hydro projects under a framework of Fast Response Ancillary Services for providing frequency regulation service.

2.4 POSOCO, in its half yearly review (November 2016) of RRAS and report on electricity market data analysis (March 2017), has illustrated the positive impact of and challenges relating to RRAS:

- **Larger balancing area and improved frequency profile:** Ancillary services act as a "slow tertiary" reserve in the present arrangement and have helped maintain frequency within the operating band (49.90-50.05 Hz) for over 75 per cent of the time.

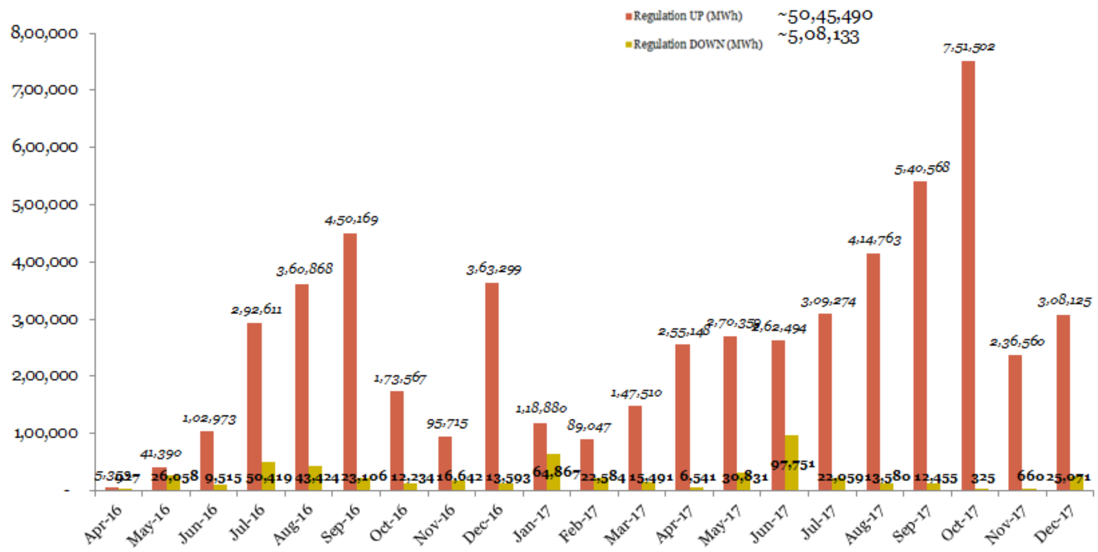
- **Real-time congestion management:** Earlier, congestion was managed in real time by applying congestion charges and in the process, all entities upstream and downstream of the congested corridor were impacted. Implementation of Ancillary Services has provided a mechanism for re-despatch of generation reserves before imposing congestion charges.

- **Grid resilience:** Ancillary services despatch has been very helpful during storms and unprecedented weather conditions. For instance, during stormy conditions in the northern region (May 24, 2016) and southern region (May 20, 2016), regulation down instructions were given, based on merit order throughout the country.

- **Implementation of merit order:** Most of the Ancillary Services (RRAS up instructions) that have been despatched were the cheaper coal- and gas-based stations. The payment is made only to performing generators, which substantially reduces the chances of gaming.

- **Reserves Quantification:** The reserves are being quantified every 15 minutes which were an abstract figure earlier. The reserve available for use under the Ancillary Services is the undespatched surplus available in the CERC-regulated generating stations.

Figure: RRAS Implementation – monthly dispatch



Source: Posoco Ancillary Service Monthly report

- Under RRAS, a total of 4,294 MUs and 482 MUs were scheduled for regulation up and regulation down, respectively, from April 2016 to Dec. 2017.

3. Challenges in Existing Regulatory Framework for Ancillary Service in India

3.1 The existing framework uses the Generating Stations that are regional entities and whose tariff is determined or adopted by the Commission for their full capacity have been mandated to provide Ancillary Services. In the existing Regulatory framework, additional mark-up is provided above variable charge of the service provider to encourage the individual participants of the market to provide these services. However, the experience in existing AS mechanism reveals certain design and operational challenges.

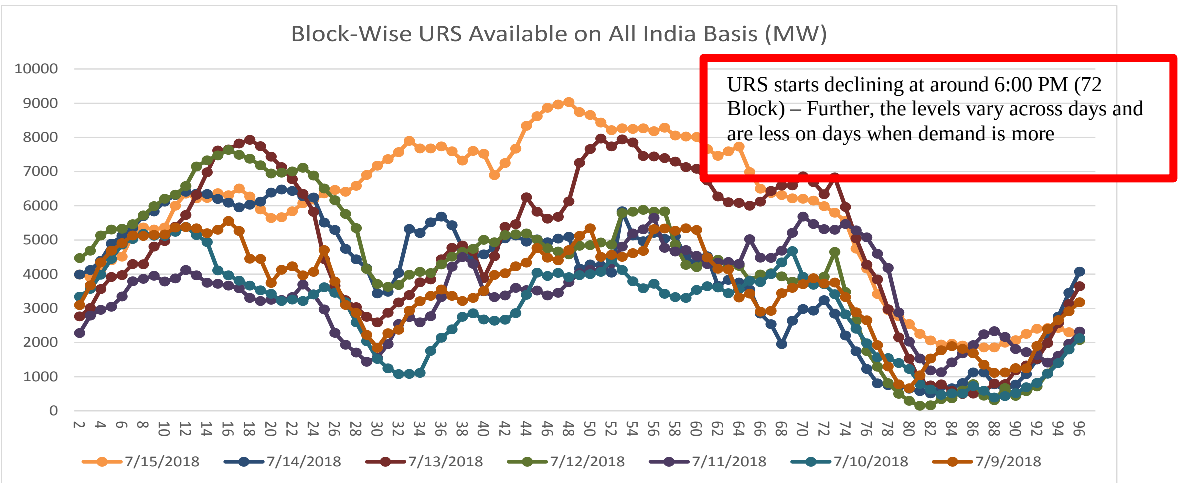
I. Key Design Challenges in Ancillary Services

<u>Need of adequate reserves quantum available for despatch</u>

3.2 POSOCO in its reports mentioned inadequacy of available reserves for AS during period of high demand. Extant Ancillary Services mechanism requires only the un-scheduled component of capacity of all the regional generators whose tariff for the full capacity is determined or adopted by the CERC. Out of this reserve, only the reserves available in running machines are available for dispatch at short notice. This at times proves to be a limiting condition on the quantum of reserves available and units under reserve shutdown need to be brought on bar.

3.3 There are periods when only a small quantum of un-despatched surplus is available for despatch, especially during high demand periods. It is the converse during low demand periods. The following picture highlights the above assertion for a week in July 2018.

Fig: URS Available between 09 July 2018 and 15 July 2018



Source: POSOCO data on Ancillary Service RRAS implementations

3.4 Decomposing the above national level un-requisitioned surplus (URS) (which is available for providing ancillary reserves) into regional URS availability reveals the need for expanding the ambit of ancillary services provision beyond the generators currently allowed to provide such services. (See Annexure1 for decomposition of URS data at regional level).

There is a need to bring in additional machines on bar and maintain spinning reserves to facilitate flexing of generation to meet ramp requirements.

<u>Adequacy of "reserves" requires a clearer definition of reserves, for example, "reserves" for how long?</u>

3.5 It has been observed that Ancillary services for balancing in India have been used for multiple hours with the objective of meeting "morning demand" (details at Annexure -2). Further, a day-on-day comparison of provision of Ancillary Services reveals several instances when the Regulation-Up service was repeated for the same blocks. A clear distinction needs to be drawn between "balancing ancillary service" and meeting demand and supply through energy markets.

<u>Need to define Adequacy in terms of "flexibility"</u>

3.6 While thermal generators, which are currently utilized for providing ancillary support, are typically classified as "Ramp-Limited Resources (RLRs)", Batteries, Plug- in Hybrid Electric Vehicles and hydro generators may be classified as "Energy-Limited Resources (ELRs)". Ramp-Limited Resources can provide energy and sustain output but take time to ramp-up and ramp-down. Energy-Limited Resources can match control signals at sub-second time levels but cannot sustain energy output which depends on the state of the charge and storage capacity. Further the Ancillary Services procurement and deployment mechanisms need to be technology agnostic. "Adequacy" in balancing resources needs to be defined in terms of ramping requirements (MW/min) along with MW.

<u>Performance Monitoring of Ancillary Services</u>

3.7 Ancillary Services are needed to maintain power system frequency within the limits. It is critical that the market has confidence that the services enabled will actually deliver their response both accurately and in a timely manner. The ability to verify the performance of units enabled to provide Ancillary Services is a key element of the ancillary service specification. The current verification clause for regulation services prescribes that a sustained failure to provide RRAS (more than three times a month) will invite reference to the Central Electricity Regulatory Commission and penalty in accordance with section 29 of the Act. It does not consider the accuracy of the delivery within that period. Hence, performance monitoring and verification of Ancillary Service providers needs to clearly specify:

(a) Tests to ensure compliance with technical minimum, ramp rates, minimum up / down time, and

(b) Procedures for regular monitoring in terms of compliance with the instruction given by the RLDC

II. Key Procedural Challenges in Ancillary Services

Gate Closure for Scheduling Process

3.8 Another important feature of advanced markets is the concept of Gate Closure. This is common in Europe as well as US markets. This implies that at some point before real-time, contracts (schedules) are frozen/finalized for the Delivery/Settlement Period. The point of time that the freeze/finalization occurs for a Delivery/Settlement Period is called Gate Closure. After Gate Closure, forward looking data for the Delivery/Settlement Period, such as physical information to the System Operator and contract (schedules) volumes, cannot be changed and the system operator takes over the responsibility for balancing the system. This is considered essential for the sake of ensuring reliability.

3.9 POSOCO in its report on implementation of Ancillary Service Regulations has highlighted limitations of absence of 'Gate Closure' in the extant RRAS Regulations.

"The original beneficiary(ies) also have the right to recall its un-requisitioned power any time as per provision of Regulations, therefore the ownership and rights remain with original beneficiary and original beneficiary(ies) should continue to pay the fixed charges. This market design has created a perverse incentive for State Utility to take a passive approach and avoid keeping reserves on bar. As stated earlier, in order to maintain grid security, NLDC/RLDC will try to keep spinning reserves in the system and they will utilize this reserve as per their requirement. The beneficiary gets a refund of fixed charges despite a passive approach. Hence, the provision regarding refund of fixed charges needs to be reviewed."

3.10 A discussion paper on Re-designing of Real Time Market, where it has been proposed to introduce the concept of gate closure.

Minimum threshold quantum for Ancillary Services

3.11 As reported by the POSOCO, many plants have a reserve of less than 10 MW, which is available for despatch under RRAS. In order to avoid too many generating stations getting a very small quantum of despatch instruction, there is a need for a minimum threshold value for RRAS up or down.

3.12 It is pertinent from the above discussion that existing regulatory framework for slow tertiary services needs to be expanded by including other generators and other services.

3.13 The teething troubles have been addressed over the last couple of years, and now the ecosystem seems primed to move on to a market-based mechanism, which will enable all generators to plan and participate and help the system operator to procure the ancillary services at the most efficient cost. The market will also be a scalable framework, which shall facilitate addition of other services.

3.14 The following sections provide an outline of the proposed market framework for Ancillary Services.

4. Market Design Options

International Experience

4.1 The challenges discussed in the previous section for efficient and economical operations for Ancillary service in India, can be compared with international experience of the Ancillary Service which are chiefly market driven. The design options for each such market differ based on the techno economic considerations such as service definition, assessment of AS required for the system, who can participate, how the service is charged, how the markets are cleared etc. (For brief discussion on different market options evolved in different countries see Annexure 3).

4.2 Analysis of international experience reveals that the Market design options for AS broadly differ based on different approaches for procurement of ancillary services (AS) and also for market clearing and settlement mechanism. As explained in the discussion paper on Real Time Market by the Commission issued for public consultation, integrated markets (where system operation as well as market operation is managed together by the system operator) are typically a characteristic of all US wholesale electricity markets, which operate day-ahead forward market and real-time imbalance market. Most European and the Australian markets follow largely exchange based market operation designs (where market operation is carried out at the exchange and system operation is handled by the system operator).

4.3 Most of the markets evolved in the US always procure AS in the day-ahead and/or in the Real-Time Market. Another characteristic of such market is co- optimization of energy market and AS market. On the other hand in EU, Independent System Operator (ISO)/ Transmission System Operator (TSO) procure the required capacity of AS well in advance (monthly or annually).

4.4 Co-optimized energy and ancillary services markets have flexibility to allow for that generation capacity to be assigned either for the production of energy or the provision of AS or both., while absence of co-optimisation runs the risk of utilising excess generation capacity for AS by giving away the flexibility of using such capacity for more valuable use depending on the system requirement. Co-optimization benefits both the power system and the generator that can provide energy and ancillary services. The power system benefits by both obtaining the needed reliability services and by minimizing operating costs for both energy and ancillary services. The generator benefits because this mechanism schedules the optimal combination of energy and ancillary services to maximize the generator's utilization. The estimate of opportunity cost of such capacity cannot be accurate if procured well in advance. Earlier experience of California and ERCOT of separating AS from Energy also points towards poor price signal and inefficient way of procurement. (*Reference : 'Why does not the EU co-optimize the procurement of ancillary service with energy? Written by Ross Baldick, published on 24th October 2017*)

4.5 On the issue of price mechanism for AS, continuous trade with pay as bid principle or uniform clearing price principle have been implemented in different AS market similar to Real Time Market Price mechanism. Continuous trading implements a pay-as-bid matching algorithm. In uniform pricing as followed in the integrated markets of US, auction participants receive the market clearing price so that the optimal strategy in competitive environments is to bid at marginal cost. In comparison, the pay-as-bid scheme used for continuous trading implies that market participants have to anticipate the clearing price and accordingly mark up their bids. There is a clear preference to Uniform Clearing Price over Continuous Trade in the advanced market.

Indian Experience

4.6 CERC vide order in Suo-motu Petition No. 11/SM/2015 dated 13th October 2015 gave a roadmap for implementation of reserves in the country. Primary, Secondary and Tertiary Reserves have been identified as 4000 MW, 3623 MW and 5218 MW respectively in the road map. While primary reserves are to be maintained mandatorily by all generators, secondary reserves are to be maintained at a regional level and tertiary reserves are to be maintained in a distributed manner in the States. Further, the Order lays down the vision of moving towards Market based framework for Ancillary Services. The relevant sections from the Order are reproduced below:

> *"5 (m) Going forward, a market based framework may be put in place from 1st April 2017 for achieving greater economy and efficiency in the system. A detailed study is required to be carried out before the market mechanism on spinning reserves is put in place. It is suggested that the NLDC be directed to commission study through a consultant in the context and submit a proposal to the Commission for approval.*
>
> *16 (d) In the long term, however, a market based framework is required for efficient provision of secondary reserves from all generators across the country. For this, NLDC/POSOCO is directed to commission a detailed study through a consultant and suggest a proposal to the Commission for implementation by 1st April, 2017, giving due*

consideration to the experience gained in the implementation of Spinning Reserves w.e.f. 1st April, 2016"

4.7 The Commission in its meeting held on 23rd March 2017 resolved to declare national reference frequency as 50Hz and decided that a high-level Expert Group be constituted consisting of representatives from CEA, POSOCO and CTU with the mandate to suggest further steps required to bring power systems operation closer to the national reference frequency.

4.8 The report submitted by the Committee examines the Indian and International experience in detail w.r.t frequency control and managing it on all time scales. As stated in the report, Frequency Control in any power system is a continuum starting from seconds to a time period of less than an hour. In the backdrop of the above continuum, the Expert Group, inter-alia recommended exploration of market mechanism for Ancillary service.

4.9 POSOCO in its report on, implementation of RRAS, have recommended moving towards market based procurement of ancillary service for a more robust design. The relevant excerpt is reproduced below:

"Once the scope of present implementation of ancillary services is enlarged from the regulated generation stations at inter-state level to include state-level generators also, a critical mass would be achieved. Moreover as more and more generators start participating in regulation services, closer monitoring of the performance of generating stations would also be needed. The implementation would also be more robust by design and subsequently, based on the experience gained, market based procurement of ancillary services could also be thought of."

5. Principles of proposed Ancillary Market Design

5.1 The international experience and national experience on AS market design underline the need for a calibrated approach to transform the extant administered Ancillary Services mechanism to a market based mechanism with the objective of increasing the ambit of potential providers of such services at efficient costs and enhanced reliability of the grid. This calibrated approach is briefly summarised in the following paras before detailing the proposed Ancillary Market for India .

Competitive and market based

5.2 Currently, only the designated power plants provide ancillary support at regulated prices. It is proposed that the Ancillary Services be procured through optimal market structures, by inviting bids from all power plants.

5.3 Given the changes in technology, generation mix and increasing decentralized generation and hence locational ancillary requirements, long term bilateral contracts for ancillary support should be avoided. Same resource can provide multiple flexibility services, for example, a generator that can provide fast tertiary response can also provide slow tertiary response. A tender which bundles multiple flexibility services has some advantages – by allowing such generators to utilize their capabilities to serve various system requirements thereby reducing the cost of provision of individual service (also known as revenue stacking).

Transparent

5.4 Transparency in markets requires that:

a) future demand for various types of ancillary requirements are clear and quantified – given the transmission constraints Ancillary Services (in terms of MW capacity along with flexibility metrics) are "locational" and need to be defined upfront, and

b) procurement is rationalised such that the same allows developers to take account of the value of Ancillary Services when new projects are at the design stage, as well as when securing finance.

c) There should be equal visibility of all Ancillary Services from procurement to instructed and delivered energy to facilitate competition.

Level playing field - Technology Agnostic Paradigm

5.5 All technologies and services should be able to compete for Ancillary Services on a level playing field. Procurement mechanism should ensure

a) consistent rewards and obligations for all providers to ensure that the least cost options are developed

b) Competition between all technologies regardless of size or type.

c) Competitive participation from both existing participants and new entrants.

Fit for the future

5.6 The Ancillary Services procurement mechanism needs to be agile enough to facilitate the evolution of various techniques in the context of changing resource mix. The mechanism should ensure that there are no barriers to entry and exit – no technology should be stranded and the system operator should be able to access the most flexible technology at least possible transition cost. This can be achieved by keeping service design as simple as possible, to avoid incorporating into the design assumptions about the technologies used to provide them.

5.7 The next level of reform in the Ancillary Services mechanism in India in being suggested keeping in view of above principle.

6. Suggested Market based Ancillary Services Mechanism

6.1 In the back drop of the discussion in the previous section and with a view to addressing constraints in the existing Ancillary Services mechanism, this section suggests design changes in the mechanism.

6.2 To recapitulate, ancillary services constitute primary, secondary and tertiary services as detailed below:

Table: Classification of Ancillary Services

Response → Attribute ↓	Inertial	Primary	Secondary	Fast Tertiary	Slow Tertiary	Generation Rescheduling/Market	Unit Commitment
Time	First few secs	Few sec - 5 min	30 s – 15 min	5 - 30 min	> 15 – 60 min	> 60 min	Hours/ day-ahead
Quantum	~ 10000 MW/Hz	~ 4000 MW	~ 4000 MW	~ 1000 MW	~ 8000-9000 MW	Load Generation Balance	Load Generation Balance
Local / LDC	Local	Local	NLDC / RLDC	NLDC	NLDC / SLDC	RLDC / SLDC	RLDC / SLDC
Manual / Automatic	Automatic	Automatic	Automatic	Manual	Manual	Manual	Manual
Centralized / Decentralized	Decentralized	Decentralized	Centralized	Centralized	Centralized/ Decentralized	Decentralized	Decentralized
Code / Order	IEGC / CEA Standard (?)	IEGC / CEA Standard	Roadmap on Reserves	Ancillary Regulations	Ancillary Regulations	IEGC	IEGC
Paid / Mandated	Mandated	Mandated	Paid	Paid	Paid	Paid	Paid
Regulated / Market	Regulated	Regulated	Regulated	Regulated	Regulated / Market	Regulated / Market	Regulated / Market
Implementation	Existing	Partly Existing	Yet to start	Yet to start	Existing	Existing	Existing

6.3 The Primary support is mandatory in nature and all generators are required to have the capability to provide the support if called for. The generators in India, therefore, are prevented from scheduling beyond their installed capacity. The Secondary Control (AGC) and fast tertiary are currently under administered mechanism and the Commission has directed pilot studies for these segments. Five-minute metering and scheduling is a necessary condition for procurement of this mechanism to go to market mechanism. As such, these two segments viz. secondary control (AGC) and fast tertiary, would be open to market mode on gaining experience from the pilot studies and the Commission may notify a date in future for introduction of markets for these two ancillary support services.

6.4 In this paper, therefore, market based mechanism is introduced for tertiary ancillary service segment. The salient features of the suggested mechanism are detailed out in this section.

A) Service Definition

6.5 Operating Reserve Requirement (for slow Tertiary) may be classified as:

Slow Spinning Reserve

- There are Operating Reserves provided by qualified Generators located within the RLDC control area that are ***already synchronized to the Power System***
- Can respond to instructions from the RLDC to change output level within 15 minutes / 30 Minutes.

Slow Non-Synchronized Reserve

- These reserves are obtained from generators / storage systems that are ***NOT synchronized with the grid*** BUT CAN respond to instructions from RLDC within 15 minutes / 30 minutes

6.6 Such Reserve Requirement could vary by seasons (for each month and / or peak and off-peak conditions and needs to assessed by RLDCs/POSOCO for each region (separated by transmission congestion)

B) How much tertiary reserves are required and how is it ascertained?

6.7 The assessment needs to be done by the National Load Dispatch Centre (NLDC) on a dynamic basis. Typically, assessment of such reserves could be based on the following:

- Sufficient Synchronized Reserve Available in such time as estimated through system studies to replace one-half of the operating capability loss caused by the most severe contingency observed
- Sufficient Reserve Available in 15 minutes and 30 minutes to replace the operating capability loss caused by the most severe contingency
- Sufficient Reserve Available in 30 minutes (to replace one and one-half times the operating capability loss caused by the most severe contingency observed under Normal Total Transfer Capability of the transmission system.
- Sufficient Reserve in 5 minutes, 10 minutes, 15 minutes and 30 minutes to return the system to a Normal State following the most severe transmission contingency.

6.8 With fast changing mix of resources in the power systems, reserves must be estimated under probabilistic and uncertain conditions. The most suitable criterion for these problems could probably be minimization of maximal losses or risk caused by incompleteness of information.

C) Who can participate?

6.9 Currently only the regulated CGS can participate in the Ancillary Services mechanism which has been classified as "slow ancillary". Going forward,

- All Inter-State / Intra-State generation (Public or Private) resources may be qualified to provide Ancillary Services

  (subject to maximum/minimum emergency/economic/regulation limits, min-run/down times, max-run times, cold/intermediate/hot start/notification times and start-up costs, and ramp-rate limits).

- RE resources, with appropriate retrofit, be qualified to provide energy and Ancillary Services at a later date.

D) **Types of tertiary Reserves**

6.10 Types of tertiary Reserves need be defined clearly and can be broadly listed below (these may be further refined by the NLDC based on the system studies of the Indian Power System):

- ***Slow Spinning Reserve*** – Operating Reserves provided by qualified Generators and qualified Demand Side Resources within the RLDC control area that are already synchronized to the Power System and can respond to instructions from the RLDC/SLDC to change output level within 15 minutes and 30 minutes.

- ***Slow Non-Synchronized Reserve*** – Reserves that can be provided by Generators, that can be started, synchronized, and loaded within 15 minutes, and 30 minutes.

- ***Total Slow Reserve*** – The sum of the ***Slow Spinning Reserve*** and ***Slow Non-Synchronised Reserve*** provided by Generators and Demand Side Resources that respond to instructions to change output or provide a demand reduction within 15 minutes and 30 minutes.

6.11 Power plants that are currently allowed to participate in the Ancillary Services Mechanism can be recalled for serving the states that have paid the capacity charges for their capacity share in these power plants. This lends uncertainty to the availability of "reserves" in the system. As noted in the Report of the Committee on Spinning Reserve (Paragraph 8.13, page 29):

"However, the aforesaid regulations seek to use only the unrequisitioned surplus of the generating stations regulated by CERC. This does not necessarily guarantee availability of generation capacity when the system operator really needs it on real time. There is thus a

need for providing a regulatory framework, for creating adequate provisioning of the system reserves including spinning reserves in India"

6.12 Therefore, in order to ensure availability of resources on a firm basis and with a view to enlarge the ambit and bringing in greater efficiency, it is proposed that:

- The extant Ancillary Services Mechanism for "slow" tertiary reserves be replaced with markets for Ancillary Services, where all resources that can provide the defined services can participate
- The markets will operate both on a Day Ahead Basis and Real Time Basis through the Market Clearing Engine of the Power Exchanges.

E) How will the services be procured and cleared?

6.13 For the slow tertiary, there shall be a Day Ahead Market where generators would bid simultaneously in Day Ahead Energy and Day Ahead Ancillary Services Market and the two shall be cleared together. While the demand curve in Day Ahead Energy Market is an aggregation of demand bid into the market, the demand curve for each type of ancillary service is put forth by the NLDC/RLDCs.

6.14 The following rules shall govern procurement:

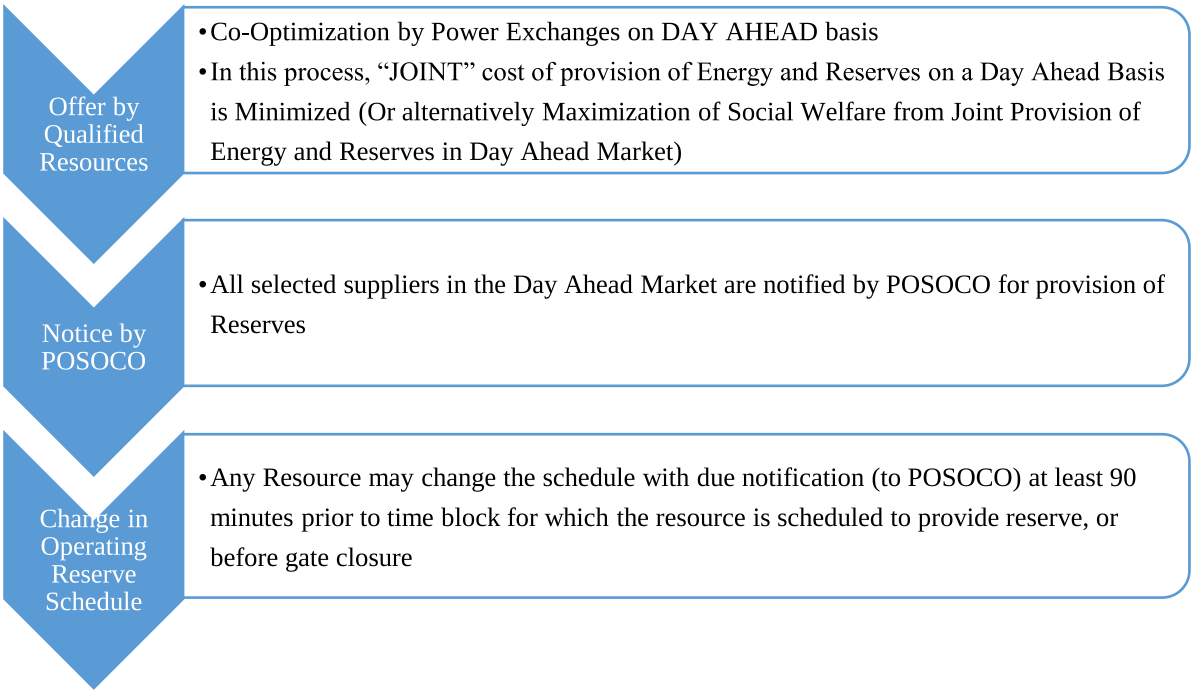
6.14.1 Based on system studies, NLDC in coordination with RLDCs and SLDCs shall decide the various types of slow tertiary services. NLDC shall further characterise these services in terms of ramp rates and duration for which continuous energy would be required from these resources.

6.14.2 Resources capable of providing tertiary reserves in the Day-Ahead commitment shall be required to submit Availability Bids for each hour of the upcoming day in the Day Ahead Market, where such offers will be co-optimized with energy bids. Each supplier will be required to mandatorily submit its availability offer for reserves (albeit the same be zero).

6.14.3 The tertiary Reserve Suppliers shall be selected for each block of time for the upcoming day through a co-optimized Day-Ahead Unit Commitment process that minimizes the total cost of Energy and tertiary Reserves, using bids submitted to Power Exchanges in the Day Ahead Market. As part of the co-optimization process, the Market Clearing Engine at Power Exchange (in coordination (iteration) with the RLDCs) shall determine how much of each Operating Reserves product particular suppliers will be required to provide in light of the

Reliability Rules and other applicable reliability standards, including the locational tertiary Reserves requirements.

6.15 Process flow on a ***day ahead basis*** is shown in the figure below:



6.16 Certain conditions may lead to a change in real time availability of resources and hence the resources designated to provide Ancillary Services shall be finally selected through a real time market.

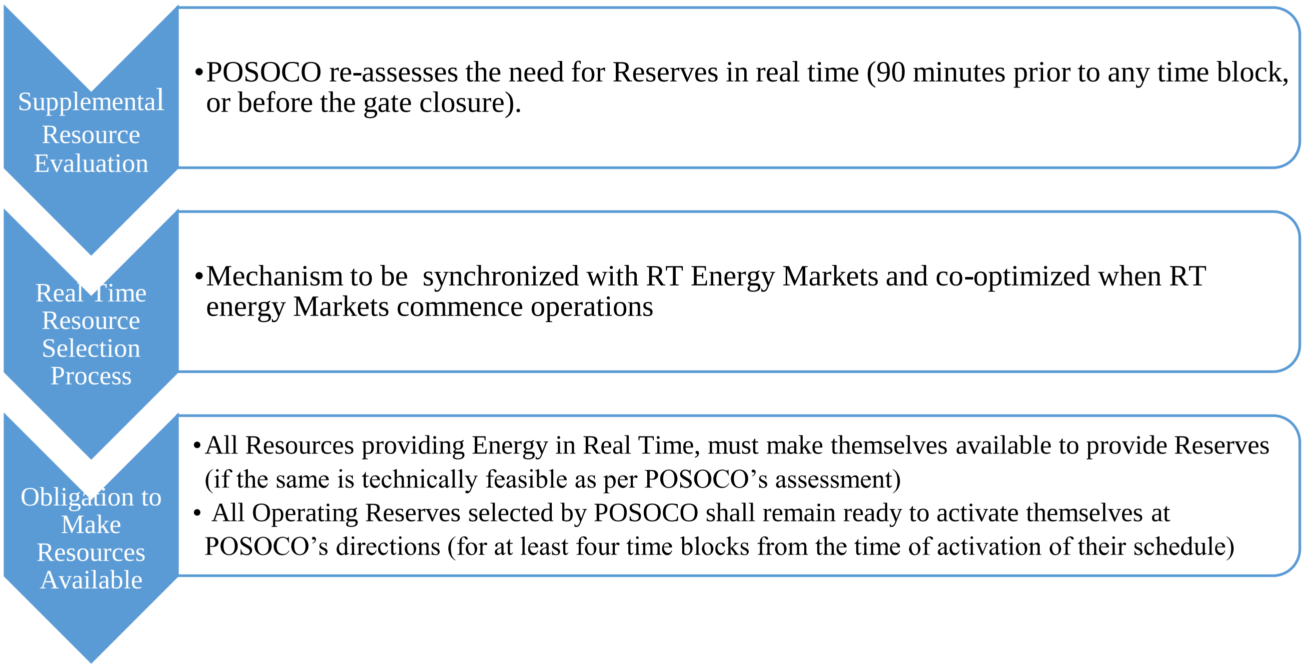
6.16.1 Resources selected to provide tertiary support in the day ahead market may advise NLDC no later than ninety minutes prior to the first hour of their Day-Ahead schedule or before the gate closure that they will not be available to provide tertiary reserves in Real-Time under normal conditions. However once committed in real time, the resources shall supply the support of designated quality (for the duration for which the service is defined).

6.16.2 In case the requirement changes in real time and the system operator does not require a supplier selected in day ahead market to provide tertiary reserve services, the supplier would be required to buy back the unserved quantum at real time prices.

6.16.3 Similarly, a supplier, selected in Day Ahead Market, that is not able to supply reserve services in real time shall also buyback the unserved quantum at real time prices.

6.17 Suppliers will thus be selected in real time based on their response rates, their applicable operating limit, and their Energy Bid through a co-optimized Real-Time commitment and dispatch process that minimizes the total cost of Energy and tertiary Reserves. This may be at the core of the real time market clearing engine operated by the power exchange. As part of the process, the RLDCs shall determine how much of each tertiary reserve product, a particular supplier will be required to provide in light of the reliability rules and other applicable reliability standards, including the locational tertiary reserves requirements.

6.18 Proposed ***intraday process flow*** is shown below:



6.19 ***Offers by Suppliers and Regulated Operating Reserve Demand Curves***

Supplier

- Offers Quantum in each type of Reserve service (15 min, 30 min – Spinning or Non-Synchronized, etc)
- Offers Price (separate for Energy and AS in the Day Ahead Market, and only Energy Price offer in Real Time Market, AS Price in Real Time is set to Rs.0 / MWh)

Buyers are the RLDCs (POSOCO)

- Based on Demand Curves for Reserves – which are different for different "congestion" zones
- Shapes of demand curves could be different for different regions

6.20 NLDC can initiate resource evaluation at any instant. The resource that is not able to demonstrate the offer parameters shall be barred from participating in these markets for a period of three years after it has failed three successive tests

6.21 As regards, clearing mechanisms, there are two alternatives, viz. Uniform Market Pricing Mechanism and continuous trading[1]. Continuous trading implies that trades can be settled whenever NLDC/RLDCs accept an offer of the provider of ancillary service. Therefore, prices may vary from trade to trade in continuous time. That is a substantial difference to auction-based markets that are cleared at discrete times. The main disadvantage of continuous trading is a lower allocated efficiency due to its inherent first-come-first-serve principle. This implies that some trades with positive welfare contribution (intra-marginal trades in discrete auctions) might not be realised while some trades with negative welfare contribution (extra-marginal trades in discrete auctions) might be settled.

6.22 As discussed in the staff paper on Real Time Markets and discussed in the literature, Uniform Clearing Price Auctions are proposed for clearing Ancillary Services Markets.

F) Pricing of Ancillary Services

6.23 Pricing of Ancillary Services is typically given by the shadow price of the Ancillary Services, i.e. the lost opportunity of the generator forgone in energy market. Therefore, the price would be calculated as the cost of the marginal resource providing the ancillary service. Such opportunity costs are best discovered through the markets.

6.24 The costs may include the bid-in cost of the resource as well as the lost opportunity cost it has from forgoing the energy market or other Ancillary Services markets (in case there are multiple markets for various kind of flexibility requirements.). Opportunity costs usually dominate the pricing of the active-power balancing Ancillary Services in organized markets (Regulation (Inertial / Primary Reserves) and the contingency (Secondary and Tertiary reserves).

[1]. Budish, E., Cramton, P., and Shim, J. (2015), 'The High-frequency Trading Arms Race: Frequent Batch Auctions as a Market Design Response', *Quarterly Journal of Economics*, **130**(4), 1547–621, November.
Cramton, P., 'Electricity Market Design', Oxford Review of Economic Policy, Volume 33, Number 4, 2017, pp. 589–612
(Ref: http://energyanalyst.co.uk/trading-behaviour-on-intraday-markets/)

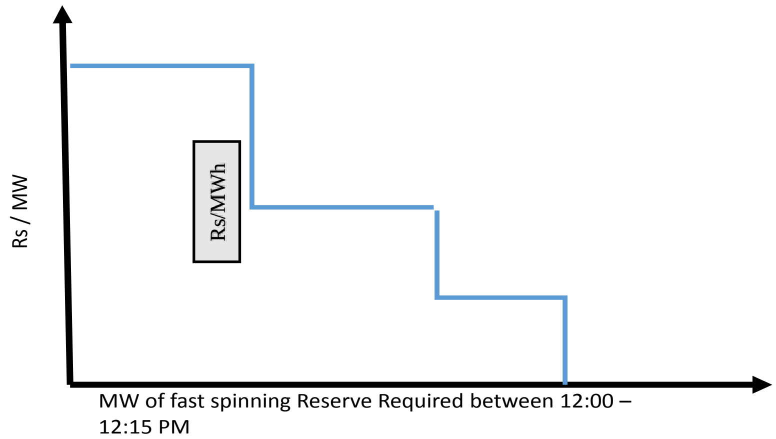
6.25 Under most conditions a generator that is supplying reserve, for example, must reduce output and forgo a profitable energy sale in order to stand ready to respond to a contingency. If that generator's variable fuel and maintenance cost was Rs 4.0/kWh and the energy market was clearing at Rs 5.0/kWh, the market would have to pay at least Rs 1.0/kWh for reserve to make the provision of reserve more attractive than the provision of energy. Providing reserves typically includes an additional cost component to cover the reduction in plant efficiency (e.g. reduction in plant efficiency that thermal generators experience when they position their throttling valves to enable fast and controlled regulation response). It may also include additional maintenance costs from the increased wear and tear of operating in this mode.

6.26 Spinning and non-spinning reserves are typically very low cost when the power system is at minimum load since there are typically numerous generators operating below full load that have the ability to rapidly increase output. There is no opportunity cost for these generators.

6.27 The fast Spinning Reserve shall be deemed to be the "highest quality" tertiary reserve, followed by fast Non-Synchronized Reserve and by slow Reserve (spinning and then non-synchronized). The RLDCs / SLDCs shall substitute higher quality tertiary reserves in place of lower quality tertiary reserves.

6.28 The RLDCs in concert with the SLDCs shall establish tertiary reserve demand curves, one for each type of tertiary reserves requirement. The demand curves shall however be subject to a price cap equivalent to the highest variable cost of the available CERC regulated generation capacities in the country. The demand curve shall be established for all types of tertiary Ancillary Services. Each tertiary reserve demand curve will apply to both the Day-Ahead Market and the Real-Time Market for the relevant product and location. Typical demand curve for a specific reserve could be:

Figure 1: Typical Demand Curve for a Specific Reserve



6.29 Uniform market clearing price would be discovered for each block of time for all services in the market.

6.30 Calculating Ancillary Services prices based on generator opportunity costs is straightforward. One illustrative example is given in the box below

6.30.1 Consider Day Ahead Position with four generators:

Consider a Day – Ahead Position with Four Generators as follows :

Day Ahead Position		Generation (MW, offered at 0)	Incremental Energy (MW)	Capacity (MW)	Spinning Reserve (MW)	Incremental Energy Price Offer (Rs/MWh)	DA Spinning Reserve availability Offer (Rs/ MWh)	Energy Schedule (MW)	Reserve Schedule (MW)
Fully Disp	Unit 1	50	150	200	10	2500	100	200	
Held Back for Reserve	Unit 2	50	150	200	10	3500	200	195	5
Econ Disp	Unit 3	50	150	200	10	4500	300	145	10
Tech Min	Unit 4	50	150	200	10	5500	400	50	10

Total Demand: 590 MW
Reserve: 25 MW

The last two columns show the market clearing volumes of Energy and Reserves through Joint Optimization of energy and reserves.

Total Demand in the System is 590 MW and demand for reserves is 25 MW

Marginal Generator is Unit 3: Hence Energy Price is Rs 4500 / MWh

Marginal Provider of Reserves is Unit 2, had it generated what was scheduled as reserve (5 MW), it would have got Rs 4500 / MWh, therefore, its opportunity value is Rs 4500 – Rs 3500 = Rs 1000 / MWh. Additionally, it has offered its reserves at Rs 200 / MWh –

Therefore total Reserve Price is Rs 1200 / MWh.

Settlement in Day-Ahead

	Energy Scheduled (MW)	Reserve Scheduled (MW)	DA- Energy Payment (Rs)	DA- Reserve Payment (Rs)
Unit 1	200	0	Rs. 9,00,000 = (200MW * Rs.4500/MW)	0
Unit 2	195	5	Rs. 8,77,500 = (195 MW * Rs.4500/MW)	Rs. 6,000= (5MW* Rs.1200/MW)
Unit 3	145	10	Rs. 6,52,000 = (145MW * Rs.4500/MW)	Rs. 12,000= (10MW* Rs.1200/MW)
Unit 4	50	10	Rs. 2,25,000 = (50MW * Rs.4500/MW)	Rs. 12,000= (10MW* Rs.1200/MW)

Unit 1 has received (200 MW *INR 4500/MWh) = INR 9,00,000 in the Day Ahead Settlement

Unit 2 has received (195 MW*INR 4500 / MWh) = INR 8,77,500 in the Day Ahead Settlement and (5 MW * INR 1200 / MWh) = INR 6000 in the Day Ahead Reserve Settlement.

Unit 3 has received (145 MW * INR 4500 / MWh) = INR 6,52,500 in DA energy settlement and (10 MW *INR 1200 / MWh) = INR 12,000 in DA Reserve Settlement

Unit 4 received (50 * INR 4500 / MWh) = INR 2,25, 000 in DA energy settlement (on account of energy) and (10 MW *INR 1200 / MWh) = INR 12,000 (on account of Reserves)

6.30.2 Now consider four alternative Real Time Scenarios

Real Time Scenario 1: Energy Demand Decreases by 80 MW, Reserve Requirement decreases by 10 MW

Real Time Scenario 1: The market clearing based on co-optimization of real time energy and reserves will be:

Day Ahead Position		Generation (MW) offer at 0 Price	Incremental Energy (MW)	Capacity (MW)	Spinning Reserve (MW)	Incremental Energy Price Offer (Rs/MWh)	RT Spinning Reserve availability Offer (Rs/ MWh)	Energy Schedule (MW)	Reserve Schedule (MW)
Fully Disp	Unit 1	50	150	200	10	2500	0	200	
Held Back for Reserve	Unit 2	50	150	200	10	3500	0	200	0
Economic Disp	Unit 3	50	150	200	10	4500	0	60	5
Technical Min	Unit 4	50	150	200	10	5500	0	50	10

Total System Demand now is: 510 MW ; Reserve Demand is 15 MW

Marginal Generator is Unit 3; hence Energy Price is Rs 4500 / MWh

Marginal Provider of Reserves is Unit 3, had it generated what was scheduled as reserve (5 MW), it would have got Rs 4500 / MWh, therefore, its opportunity value is Rs 4500 – Rs 4500 = Rs 0 / MWh

Settlement for Scenario -1

	Change in Energy Schedule (RT-DA)	Change in Reserve Schedule (RT-DA)	RT Energy Payment (Rs)	RT Reserve Payment (Rs)	Additional Cost (Rs)	Profit (Rs)
Unit 1	0	0		0		
Unit 2	+5	-5	22500 (5*4500)	0 (-5*0)	17500 (5*3500)	5000
Unit 3	-85	-5	-382500 (-85*RT-MCP)	0 (-5*0)	-382500 (-85*4500)	0
Unit 4	0	0	0	0		
Net				0		
Load	0					

Decline in demand for Reserve Services in Real Time (RT) leads to reduction in price of reserves in RT

Unit 2 and Unit 3 had received payments for Reserve Services in Day Ahead (DA) reserve market purchase back 5 MW each in RT Reserve Market at RT Prices (which are Zero in this case)

Note that:

Unit 1 has received (200 MW *INR 4500/MWh) = INR 9,00,000 in the Day Ahead Settlement

Unit 2 has received (195 MW*INR 4500 / MWh) = INR 8,77,500 in the Day Ahead Settlement and (5 MW * INR 1200 / MWh) = INR 6000 in the Day Ahead Reserve Settlement – However, it has to generate 5 MW more in RT Energy Market and since the energy price in RT market is also INR 4500 / MWh it gets an additional revenue in RT markets and incurs additional costs of generation (as indicated in the settlement table above). Unit 2 was scheduled to provide reserve of 5 MW (in DA), which is now not required in RT, therefore, the same is bought back by the unit at RT Ancillary Prices (which incidentally are Zero in the present case).

Unit 3 has received (145 MW * INR 4500 / MWh) = INR 6,52,500 in DA settlement and (10 MW *INR 1200 / MWh) = INR 12000 in DA Reserve Settlement. However, since Unit 3 has to generate 85 MW less as a result of RT settlement, Unit 3 must “buy back” this power at RT Energy Prices at RT rates (=85 MW * INR 4500/MWh = INR 3,82,500). Unit 3 is not required to provide reserves as a result of RT Reserve Settlement and must buy back 5 MW of reserves. Therefore, net payments to Unit 3 are (INR 6,52,500 – INR 3,82,500) = INR 2,70,000 on account of Energy and INR 12000 on account of Reserves.

The schedule of Unit 4 does not change in RT, therefore, the payments are as per the prices in DA markets – INR 2,25,000 (on account of energy) and INR 12000 (on account of Reserves).

Real Time Scenario 2: Generator which was not scheduled on a Day Ahead Basis is Available in RT, Demand increases by 360 MW, Reserve Requirement increases by 10 MW

Real Time Scenario 2: The results of real time market clearing are shown below:

Day Ahead Position		Generation (MW) offer at 0 price	Incremental Energy (MW)	Capacity (MW)	Spinning Reserve (MW)	Incremental Energy Price Offer (Rs/MWh)	RT Spinning Reserve availability Offer (Rs/ MWh)	Energy Schedule (MW)	Reserve Schedule (MW)
Fully Disp	Unit 1	50	150	200	10	2500	0	200	
Held Back for Reserve	Unit 2	50	150	200	10	3500	0	195	5
Econ Disp	Unit 3	50	150	200	10	4500	0	190	10
Tech Min	Unit 4	50	150	200	10	5500	0	190	10
	Unit 5	50	150	200	10	6500	0	175	10

Total System Demand: 950 MW ; Demand for Reserves: 35 MW

RT Energy Price: Rs 6500/ MWh, RT Reserve Price: = (6500-3500) + 0 = Rs 3000/ MWh

Changes in RT are settled at RT Rates only

Settlement for Real Time Scenario 2 is shown below:

	Change in Energy Schedule (RT-DA)	Change in Reserve Schedule (RT-DA)	RT Energy Payment (Rs)	RT Reserve Payment (Rs)	Additional Cost (Rs)	Profit (Rs)
Unit 1	0	0		0		
Unit 2	0	0	0	0	0	0
Unit 3	+45	0	292500 (45*RT-MCP (6500))	0	202500 (45*4500)	90000
Unit 4	+140	0	910000 (140*RT-MCP)	0	770000 (140*5500)	140000
Unit 5	+175	+10	1137500 (175*RT-MCP)	30000 (10*3000)	812500 ((175-50)125*6500)	355000
Net			2340000	0	1785000	
Load	360					

Unit 2 remains the marginal provider of Ancillary Reserves, however, the value of reserves in RT increases to Rs 3000/MWh because the RT Energy Price is higher

This Scenario can be compared with Scenario 3, where the RT Reserve Price is lower

Note that:

In DA Settlement:

As discussed in Scenario 1: Unit 1 receives INR 900,000 in DA Energy Settlement. There is no change in RT for Unit 1

Unit 2 receives INR 877,500 in DA Energy Settlement and INR 6000 in Reserve Settlement. There is no change in RT

Units 3 serves additionally 45 MW and gets compensated for the same at RT Energy Settlement price. No change in Reserve Schedule – Unit 3 will continue to provide reserves at DA prices despite an increase in RT reserve price.

Unit 4 was scheduled 50 MW in DA Market and got INR 225,000 in DA energy settlement and INR 12000 in DA Reserve Settlement. It supplies an additional 140 MW in RT to meet additional demand at RT prices, however continues to provide 10 MW of reserves at the DA prices despite an increase in RT reserve prices.

Unit 5 was not there in the DA market. It gets to schedule 175 MW in RT Energy market and 10 MW additional in RT Reserve markets and gets compensated at RT prices.

Real Time Scenario 3: Generator which was not scheduled on a Day Ahead Basis is Available in RT (Unit 5) and Demand increases by 360 MW

Real Time Scenario 3: The outcome of market clearing is shown below:

Day Ahead Position		Generation (MW) offer at 0 price	Incremental Energy (MW)	Capacity (MW)	Spinning Reserve (MW)	Incremental Energy Price Offer (Rs/MWh)	RT Spinning Reserve availability Offer (Rs/ MWh)		Energy Schedule (MW)	Reserve Schedule (MW)
Fully Disp	Unit 1	50	150	200	10	2500	0		200	
Held Back for Reserve	Unit 2	50	150	200	10	3500	0		200	0
Econ Disp	Unit 3	50	150	200	10	4500	0		195	5
Tech Min	Unit 4	50	150	200	10	5500	0		190	10
	Unit 5	50	150	200	10	6500	0		165	10

Demand: 950 MW ;   Reserve Demand: 25 MW

RT Energy Price: Rs 6500/ MWh,   RT Reserve Price: = (6500-4500) + 0 = Rs 2000/ MWh

Changes in RT are settled at RT Rates only

The Settlement is shown in the table below:

	Change in Energy Schedule (RT-DA)	Change in Reserve Schedule (RT-DA)	RT Energy Payment (Rs)	RT Reserve Payment (Rs)	Additional Cost (Rs)	Profit (Rs)
Unit 1	0	0		0		
Unit 2	+5	-5	32500 (5*RT-MCP)	-10000 (-*2000)	17500 (5*3500 (Energy Bid Price))	5000
Unit 3	+50	-5	225000 (50*RT-MCP)	-10000 (-5*2000)	225000 (50*4500)	90000
Unit 4	+140	0	910000 (140*RT-MCP)	0	770000 (140*5500)	140000
Unit 5	+165	+10	1072500 (165*RT-MCP)	20000 (10*2000)	747500 ((165-50)115*6500)	345000
Net			2340000	0	1760000	
Load	360					

Net Real Time load must cover its shortfall in the energy market. However the load bought sufficient operating reserves day-ahead, so any increases in a generators reserve schedule is offset by another generators reduction.

Note that:

For Unit 1, there is no change in settlement and it receives as per DA settlement

For Unit 2, it had received INR 877,500 in DA Energy Settlement and INR 6000 in DA Reserve Settlement. In RT, it needs to serve 5 MW more in energy market and hence gets compensate for the same at RT MCP. However, it is now not required to provide a reserve of 5 MW, and therefore must "buy back" 5 MW of reserves at RT prices. Note that, Unit 2 was paid INR 6000 in DA Reserve settlement, but is now required to buy back the reserves at RT reserve price if INR 2000 / MWh, which is higher than the DA Reserve price of INR 1200 / MWh. Therefore, Unit 2 gets an additional amount of INR 32500 in RT Energy Markets, it has to pack back INR 10000 on account of higher RT reserve prices.

Unit 3, similarly supplies additional 50 MW in RT Energy Markets and gets compensated for the same. However, it has to "pay back" for the 5 MW reserves (at higher RT Reserve prices) which are now not needed in RT.

Unit 4 supplies additional RT Energy and gets compensated at RT prices but does not get any additional amount over the DA reserve settlement despite RT Reserve prices being higher than DA reserve prices.

Unit 5 was anyway not there in the DA market

Real Time Scenario 4: Generator which was not scheduled on a Day Ahead Basis is Available in RT Market

Real Time Scenario 4: The real time market clears as:

Day Ahead Position		Generation bid (MW) at 0 price	Incremental Energy (MW)	Capacity (MW)	Spinning Reserve (MW)	Incremental Energy Price Offer (Rs/MWh)	RT Spinning Reserve availability Offer (Rs/ MWh)		Energy Schedule (MW)	Reserve Schedule (MW)
Fully Disp	Unit 1	50	150	200	10	2500	0		200	
Held Back for Reserve	Unit 2	50	150	200	10	3500	0		200	0
Econ Disp	Unit 3	50	150	200	10	4500	0		90	5
Tech Min	Unit 4	50	150	200	10	5500	0		50	10
	Unit 5	50	150	200	10	6500	0		50	10

Energy Demand Stays as 590 MW; Reserve Demand too remains the same at 25 MW as in Day Ahead Market

RT Energy Price: Rs 4500/ MWh, RT Reserve Price: 0 = (4500-4500) + 0 = Rs 0/ MWhr Changes in RT are settled at RT Rates only

Settlement happens as shown below:

	Change in Energy Schedule (RT-DA)	Change in Reserve Schedule (RT-DA)	RT Energy Payment (Rs)	RT Reserve Payment (Rs)	Additional Cost (Rs)	Profit (Rs)
Unit 1	0	0		0		
Unit 2	+5	-5	22500 (5*RT-MCP)	0	17500	5000
Unit 3	-55	-5	-247500 (-55*RT-MCP)	0	-247500 (-55*Energy Bid Price)	0
Unit 4	0	0		0		
Unit 5	+50	+10	225000 (50*RT-MCP)	0		22500
Net			0			
Load						

In this scenario RT Load has not changed from DA, only additional generator comes in – RT Energy Costs just get redistributed between generators and there is no additional payout. All additional revenues required to pay generators not scheduled day-ahead is recovered from other generators who were scheduled day-ahead and were not in RT.

Note that:

Unit 1 serves the power system as per its schedule in the DA Market

Unit 2 gets an additional amount for serving 5 MW extra in Energy Market but has to buyback 5 MW that it was scheduled for in DA Reserve Market in RT. Since the RT Reserve price is zero, there is effective no payment to be made for buyback.

Unit 3 is required to buy back in the RT energy market. Remember that Unit 3 was scheduled 145 MW in DA market and had got INR 65200 in DA Energy settlement. It has to buy back 55 MW in RT Energy settlement at the RT Price and hence has to pay back INR 247500 to the system.

No change for Unit 4

Unit 5 was not scheduled in DA

6.31 While, the above illustrations explain the co-optimisation and settlement of Regulations Up Service, a framework on similar lines will apply for Regulations Down Service.

G) How is the performance of resources determined?

6.32 Performance matrix, in terms of the accuracy, delay and precision in response to request from RLDCs and non-supply of services will be used to release the payments to such reserves. Detailed non-compliance penalties would need to be defined in terms of:

- Non-compliance for delivery of power
- Non-compliance with minimum generation;
- Non-compliance with ramp rates;
- Non-compliance with minimum up times and minimum down times;
- Non-compliance with time from synchronisation to minimum generation;
- Non-compliance with time from minimum generation to desynchronization, and

Non-compliance of an output level equal to that required by the RLDC for the required duration in an extreme case, it may lead to disqualification of the resource from these markets for a defined period.

H) How will the Transmission Corridor Allocation and Congestion Management be handled?

6.33 It would be desirable that POSOCO declares in advance the transmission corridor margin available for real-time/ ancillary services transaction. Accordingly, Power exchanges shall factor in the said margin available while clearing the market. The congestion management shall be handled as per the existing practice including by way of market splitting.

I) How would the charges for tertiary services recovered?

6.34 Ancillary Services costs are not typically allocated based on cost causation[2], except for regulation Frequency Control Ancillary Services (FCAS) (Primary Control) in Australia, where regulation FCAS recovery is calculated on a causer pays basis, i.e., the amount paid by Australian Electricity Market Operator (AEMO) for the FCAS service is recovered from market participants responsible for causing the need for the service. Therefore, regulation FCAS recovery is calculated on the basis of a participant's Market Participant Factor (MPF), also referred to as Causer Pays Contributing Factors.

6.35 For the secondary and tertiary control services, charges are socialized based either on energy consumption or demand (in UK and Australia). This is in spite of the fact that some customers differ dramatically in their ancillary service consumption. For example, even if a state DISCOM is responsible for half of the ancillary service burden, yet pays for a much lower percentage of the ancillary service cost through the bundled rate. There have been recent research efforts to assess specific ancillary service charges on variable renewable suppliers even though the impact of nonconforming loads is typically significantly higher.

6.36 As the power sector in India transitions to include AS markets for tertiary services, it is proposed that initially, the charges be recovered from the Deviation Settlement Mechanism pool. Once the AS markets have stabilized, the charges be recovered as a "price adder" to the NLDC/ RLDC service charges and recovered from the grid connected entities on per unit of energy basis or as price adder in UI/DSM charges.

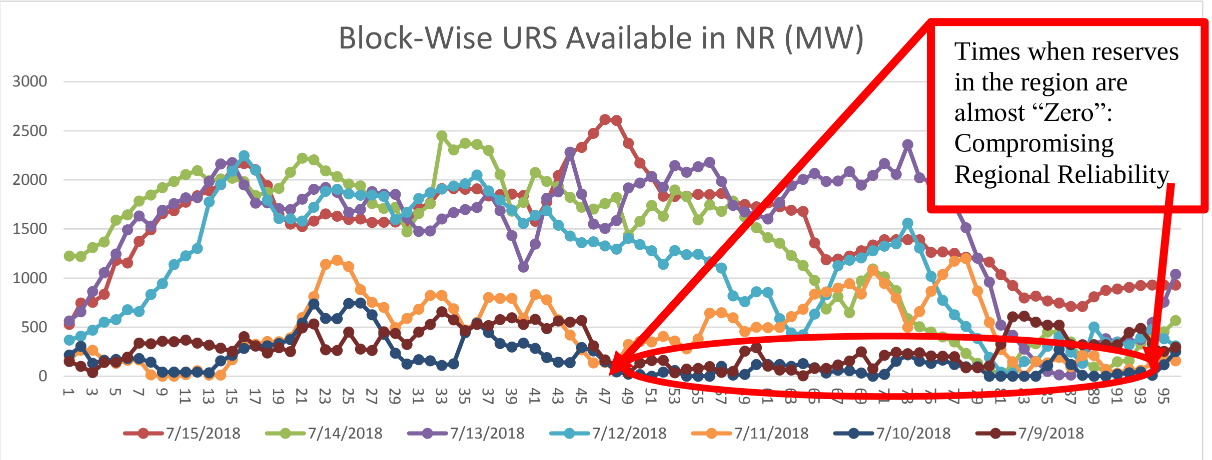
***

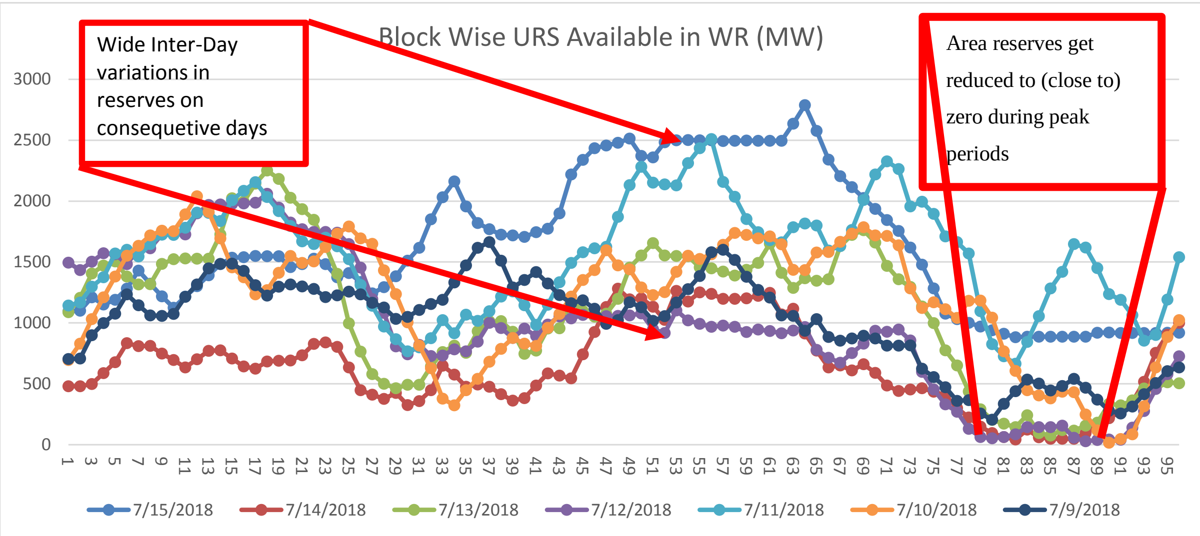
[2] Research, however, indicates possibilities of allocating the costs of Ancillary Services based on causation: https://www.ethz.ch/content/dam/ethz/special-interest/itet/institute-eeh/power-systems-dam/documents/Dissertationen/Diss-Haring/Haring-ETH-22555.pdf

Annexure 1

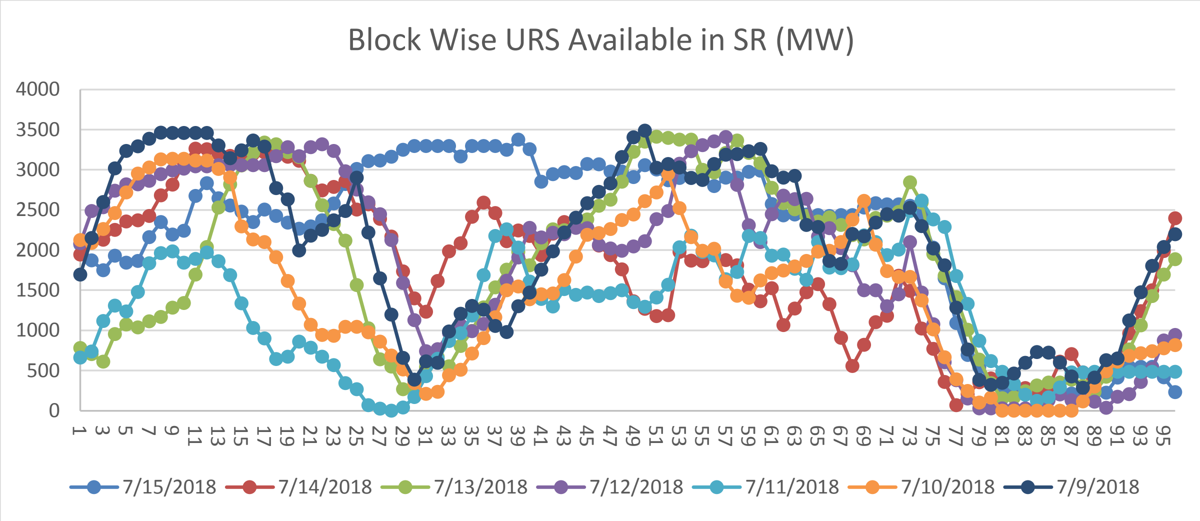
<u>Decomposition of Regional Level URS</u>

Regional Level Adequacy of Reserve for AS in India – during high demand

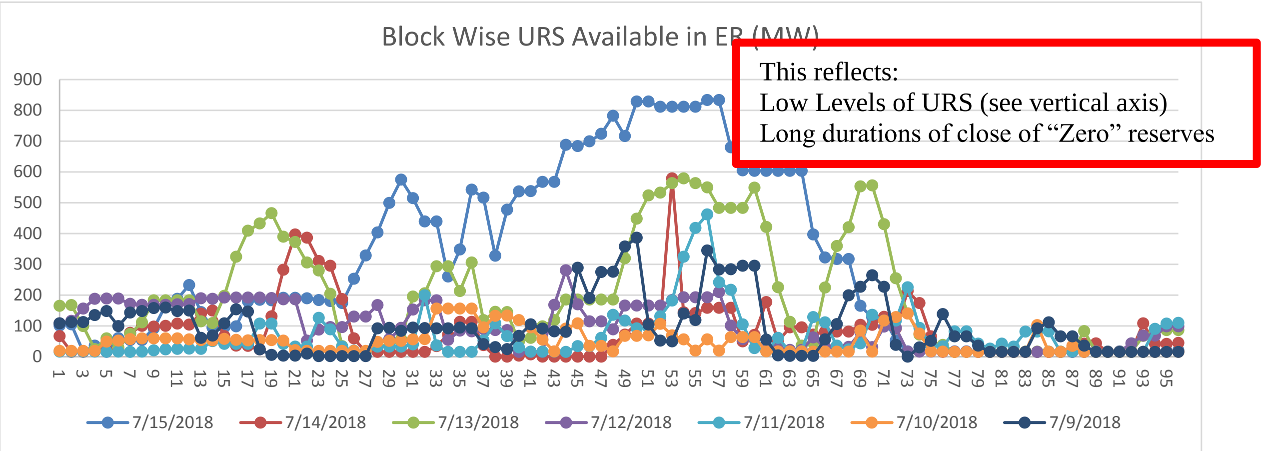




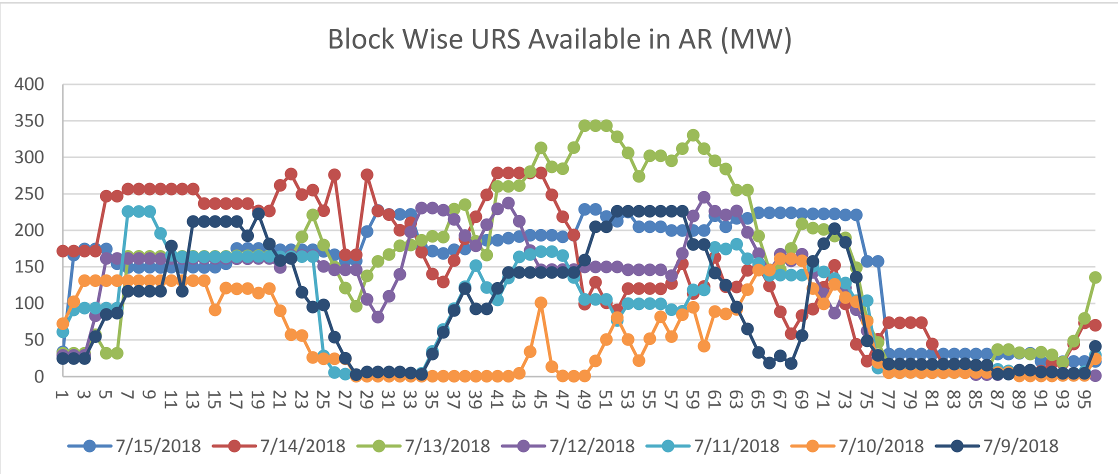
In the above figures, the day time variability will get further accentuated as the share of RE (especially solar) increases in the system.



In addition to the challenges illustrated in the figures above, in ER and North Eastern Region (AR), the levels of URS (and hence the AS support) is also considerably limited.



While transmission networks and nation-wide availability of reserves can help under certain conditions, each area needs to have a minimal level of reserve to manage during periods of transmission contingency.



Annexure 2

Table: Reasons for use of Ancillary Services in India

SNO	Message No	Type	Start Date/Time	End Date/Time	MW	Reason	Comments	Generators Despatched	Duration of Service (Hours)
1	20180203-001	UP	03-02-2018 04:30	03-02-2018 09:30	1000	Low Frequency, Trend of load met	To meet Morning Demand	SINGRAULI[NR], SASAN[WR], RIHAND1[NR], RIHAND2[NR], RIHAND3[NR], VSTPS IV[WR], VSTPS V[WR], VSTPS III[WR], VSTPS I[WR], NSPCL[WR], BRBCL[ER], RSTPSU7[SR], RSTPSU1TO6[SR], KHSTPP-II[ER], FSTPP I & II[ER], SIMHST2[SR], KHSTPP-I[ER], MOUDA_II[WR], UNCHAHAR3[NR], UNCHAHAR2[NR], UNCHAHAR1[NR], MOUDA[WR], NLCIIST1[SR], BGTPP[AR], JHAJJAR[NR], DADRI_GF[NR], NTPL[SR], DADRIT[NR], RGPPL_IR[WR], KUDGI[SR]	05:00
2	20180203-002	UP	03-02-2018 05:45	03-02-2018 09:45	1012	Low Frequency, Trend of load met	To meet morning peak ramp.	BRBCL[ER], KHSTPP-II[ER], MOUDA_II[WR], UNCHAHAR3[NR], MOUDA[WR], NLCIIST1[SR], NLCIIST2[SR], BGTPP[AR], JHAJJAR[NR], DADRI_GF[NR], NTPL[SR], DADRIT[NR], RGPPL_IR[WR], KUDGI[SR]	04:00
3	20180203-003	UP	03-02-2018 09:15	03-02-2018 11:00	838	Trend of load met		NSPCL[WR], BRBCL[ER], KHSTPP-II[ER], KHSTPP-I[ER], MOUDA_II[WR], MOUDA[WR], BGTPP[AR], JHAJJAR[NR], VALLURNTECL[SR], NTPL[SR], DADRIT[NR], RGPPL_IR[WR], KUDGI[SR]	01:45
4	20180203-004	UP	03-02-2018 09:45	03-02-2018 10:15	497	Trend of load met		BRBCL[ER], KHSTPP-II[ER], FSTPP-III[ER], NLCEXP[SR], NLCIIST1[SR], NLCIIST2[SR], JHAJJAR[NR], VALLURNTECL[SR], NTPL[SR]	00:30
5	20180203-005	UP	03-02-2018 10:45	03-02-2018 12:00	500	Trend of load met		NSPCL[WR], BRBCL[ER], KHSTPP-II[ER], FSTPP-III[ER], SIMHST2[SR], KHSTPP-I[ER], NLCEXP[SR], MOUDA[WR], NLCIIST2[SR], NLCIIST1[SR], JHAJJAR[NR]	01:15
6	20180203-006	UP	03-02-2018 14:00	03-02-2018 16:00	800	Trend of load met		RIHAND3[NR], NSPCL[WR], BRBCL[ER], BARH[ER], RSTPSU7[SR], RSTPSU1TO6[SR], GANDHAR-NAPM[WR], KHSTPP-II[ER], FSTPP I & II[ER], FSTPP-III[ER], SIMHST2[SR], KHSTPP-I[ER], MOUDA_II[WR], UNCHAHAR3[NR], UNCHAHAR2[NR], UNCHAHAR1[NR], NLCEXP[SR], NLCTS2EXP[SR]	02:00
7	20180203-007	UP	03-02-2018 15:00	03-02-2018 16:00	500	Trend of load met		BRBCL[ER], BARH[ER], RSTPSU1TO6[SR], KHSTPP-II[ER], FSTPP I & II[ER], FSTPP-III[ER], SIMHST2[SR], KHSTPP-I[ER]	01:00
8	20180203-008	UP	03-02-2018 16:00	03-02-2018 20:00	600	Low Frequency, Trend of load met		RIHAND3[NR], NSPCL[WR], BRBCL[ER], BARH[ER], RSTPSU1TO6[SR], GANDHAR-NAPM[WR], KHSTPP-II[ER], FSTPP-III[ER], SIMHST2[SR], KHSTPP-I[ER], MOUDA_II[WR], UNCHAHAR1[NR], UNCHAHAR2[NR], UNCHAHAR3[NR], MOUDA[WR], NLCIIST1[SR], NLCIIST2[SR], JHAJJAR[NR], DADRI_GF[NR], NTPL[SR], DADRIT[NR], RGPPL_IR[WR], KUDGI[SR]	04:00
9	20180203-009	UP	03-02-2018 17:00	03-02-2018 18:00	464	Trend of load met		FSTPP I & II[ER], KHSTPP-I[ER], MOUDA[WR], BGTPP[AR], DADRT2[NR], JHAJJAR[NR], NTPL[SR], DADRIT[NR], RGPPL_IR[WR], KUDGI[SR]	01:00
10	20180203-010	UP	03-02-2018 18:00	03-02-2018 20:00	823	Trend of load met	To meet with ramping of evening peak demand	NSPCL[WR], BRBCL[ER], MOUDA_II[WR], UNCHAHAR3[NR], UNCHAHAR2[NR], UNCHAHAR1[NR], MOUDA[WR], BGTPP[AR], DADRT2[NR], JHAJJAR[NR], VALLURNTECL[SR], DADRI_GF[NR], NTPL[SR], DADRIT[NR], RGPPL_IR[WR], KUDGI[SR]	02:00

Annexure -3

Various International Market Designs for Ancillary Services

A) Need for Service Definition

Electricity system operators (SO) need to determine the optimal quantity and quality of electricity ancillary services to procure in a market increasingly characterized by intermittent renewable electricity generation. Need for a clear service definition is aptly discussed by Greve et. al[3]:

"To ensure the reliability and efficiency of the system, the SO needs the right services to be delivered. However, what are the right services? A SO might have chosen to work with a 1s service, 10s service and/or 1 hour service. Why not a 0.5s service or a guaranteed delivery in 13s? Current services may have been of interest to the majority of suppliers, maybe the bigger ones, maybe they were the right services some years ago. <u>As we are in a world of asymmetric information between the SO and the market, the selling mechanism needs to be able to test the market for the right services at each allocation procedure.</u> " (Emphasis Added)

For example:

<u>In PJM:</u>

- The equivalent of "slow tertiary" may be considered as "Reserve" Ancillary Services
- "Reserve" Ancillary Services are electricity supplies that are not currently being used but can be quickly available in the case of an unexpected loss of generation.
- These are further classified as
  - **Primary Reserves:** The amount of power that can be received within 10 minutes. This power can be from:
    - Generators that are synchronized to the power grid (called **Synchronized Reserves**) or offline (called **Quick Start Reserves**)
    - Certain loads, designated as demand side response, which can be removed from the grid
  - **Supplemental Reserves**: The amount of power that can be received within 10 to 30 minutes. This power too can be from Synchronized or offline resources

<u>In NYISO:</u>

- Operating Reserve Products are:
  - 10 Minute Spinning and Non-Synchronized Reserves

[3] Greve, T., Teng, F., Pollitt, M., Strbac, G. (2017), A system operator's utility function for the frequency response market, EPRG Working Paper No.1713.

- 30 Minute Spinning and Non-Synchronized Reserves

In AEMO (Australian Energy Market Operator):

- Contingency Services are of the following types:
  - Fast Raise (6 Second Raise): 6 second response to arrest a major drop in frequency following a contingency event
  - Fast Lower (6 Second Lower): 6 second response to arrest a major rise in frequency following a contingency event.
  - Slow Raise (60 Second Raise): 60 second response to stabilise frequency following a major drop in frequency.
  - Slow Lower (60 Second Lower): 60 second response to stabilise frequency following a major rise in frequency.
  - Delayed Raise (5 Minute Raise): 5 minute response to recover frequency to the normal operating band following a major drop in frequency.
  - Delayed Lower (5 Minute Lower): 5 minute response to recover frequency to the normal operating band following a major rise in frequency.

In UK (National Grid)

- Fast Reserve Services have the following technical characteristics:
  - active power delivery must start within two minutes of the dispatch instruction;
  - a delivery rate in excess of 25MW/minute;
  - the reserve energy should be sustainable for a minimum of 15 minutes; and
  - must be able to deliver minimum of 50MW.
- Short Term Operating Reserve (STOR) Services have the following characteristics:
  - offer a minimum of 3 MW of generation or steady demand reduction. This can be aggregated from more than one site; and
  - sustain this response for a minimum of two hours.
  - Providers should be able to respond to an instruction from us within a maximum of 240 minutes, although response times within 20 minutes are preferable.

The differences in service definition illustrate the need for developing slow tertiary requirements in accordance with the topology, generation mix and nature of demand in the power system.

B) How much tertiary reserves are required and how is it ascertained?

In PJM

In PJM (following are the extracts from PJM Manual 11: Energy & Ancillary Services Market Operations Revision: 96 Effective Date: July 1, 2018, with Emphasis Added):

- PJM must ensure that adequate synchronized and primary reserves MW are procured and maintained to recover from the ***loss of the single largest generator contingency, which is normally the largest online generator's output***. However, there is, at times, an outage condition at a station whereby ***a single fault would trip multiple generators resulting in a loss of generation greater than the largest single generator. In such instances, PJM will carry an increased reserve requirement in equivalent summation of output of those multiple generators.***
- At times, ***anticipated heavy load conditions may result in PJM operators carrying additional reserves to cover increased levels of operational uncertainty.*** PJM may extend the Primary Reserve and Synchronized Reserve Requirements in the Market Clearing Engines during the on-peak period in order to incorporate these actions in energy and reserve pricing when a Hot Weather Alert, Cold Weather Alert or an escalating emergency procedure has been issued for the Operating Day. ***The extended Synchronized Reserve Requirement and Primary Reserve Requirement will be equal to the existing reserve requirement plus the sum of any additional MW brought online for that hour by PJM dispatch to account for operational uncertainty after the second resource commitment which occurs after 1415 the day prior to the Operating Day.*** If reserve deliverability issues are anticipated, then the requirements for the Sub-Zone(s) in which the additional resources are located will be extended.
- **In the case of non-synchronized resources:** There is no defined, hourly requirement for Non-Synchronized reserves but it will be procured when economic to meet the Primary Reserve requirements.

In NYISO:

- Total Operating Reserve must be greater than or equal to one and one-half times the largest single Contingency (in MW) as defined by the NYISO;
- Total 10-Minute Reserve must be greater than or equal to the largest single Contingency (in MW) as defined by the NYISO;
- 10-Minute Spinning Reserve must be greater than or equal to one-half of the largest single Contingency (in MW) as defined by the NYISO.
- At all times sufficient total 10-minute reserve is maintained to cover the energy loss due to the most severe Normal Transfer Criteria contingency within the NY Control Area (NYCA) or the energy loss caused by the cancellation of an interruptible import transaction (neighboring control area to NYCA) whichever is greater. In addition:
    - The NYISO may establish additional categories of Operating Reserves if necessary to ensure reliability.
    - The NYISO ensures that providers of Operating Reserves are properly located electrically so that transmission constraints resulting from either commitment or dispatch of units do not limit the ability to deliver Energy to Loads in the case of a Contingency.
    - The NYISO ensures that Capacity counted toward meeting NYCA Operating Reserve requirements is not counted toward meeting Regulation and Frequency Response Service requirements.

<u>In Australia (AEMO):</u>

- Spinning Reserve Services: 70% of largest generator or network contingency resulting in loss of generation[4]

<u>In UK:</u>

- The need for Short Term Operating Reserve (STOR) varies depending on
    - the time of year, the time of week and time of day,
    - the system demand profile at that time.
    - To reflect this, National Grid splits the year into a number of Seasons, for both Working Days (including Saturdays) and Non-Working Days (Sundays and most Bank Holidays), and specifies the periods in each day that Short Term Operating Reserve is required. These periods are referred to as Availability Windows

C) Who can participate?

<u>In PJM</u>[5]:

Resources participating in the <u>Synchronized Reserve</u> market are divided into two Tiers:

- Tier 1 is comprised of all those resources on line following economic dispatch and able to ramp up from their current output in response to a Synchronized Reserve Event, or Demand Resources capable of reducing load, within 10 minutes.
    - Tier 1 estimates for resource types that cannot reliably provide Synchronized Reserve service are set to zero MW during the market clearing process. Such resource types include, but are not limited to: Nuclear, Wind, Solar, Energy Storage Resources, and Hydro units. Owners of any specific resource(s) or these resource types may request an exception from the default zero MW estimated value of their resource(s) if they notify PJM that the resource(s) are able to reliably provide Tier 1 Synchronized Reserve.
- Tier 2 consists of:
    - additional capacity that is synchronized to the grid and operating at a point that deviates from economic dispatch (including condensing mode) to provide additional Synchronized Reserve not available from Tier 1 resources within ten (10) minutes; and
    - dispatchable load resources that have controls in place to automatically drop load in response to a signal from PJM within ten (10) minutes.

<u>Non-Synchronized Reserves include</u>:

- Non-synchronized reserves may be provided only by generation resources electrically within the PJM RTO.

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[4] https://www.erawa.com.au/cproot/19328/2/AEMO%20Ancillary%20Services%20Requirements%20decision%202018-19.PDF

[5] http://www.pjm.com/~/media/documents/manuals/m11.ashx

- Non-synchronized reserve resources are defined as generation resources that meet the following eligibility requirements to provide non-synchronized reserve.
    - The Non-Synchronized Reserve capability of a generation resource shall be the increase in energy output or achievable by the generation resource within a continuous 10-minute period provided that the resource is not synchronized to the system at the initiation of the response Examples of Non-Synchronized Reserve resources generally include:
        - Shutdown run-of-river, pumped hydro, industrial combustion turbines, jet engine/ expander turbines, combined cycle and diesels.
        - Demand Resources will not be eligible to provide Non-Synchronized Reserve
        - Generation resources that have designated their entire output as emergency will not be considered eligible to provide non-synchronized reserves.
        - Generation resources that are not available to provide energy will not be considered eligible to provide non-synchronized reserves.

In NYISO:

- **Spinning Reserve** can be provided by:
    - Generators or Demand Side Resources that are not supporting their Demand Reduction through the use of Local Generation that are ISO-Committed Flexible or Self-Committed Flexible; are operating within the dispatchable portion of their operating range and are capable of responding to NYISO instructions to change their output level within ten minutes
- **10-Minute Non-Synchronized Reserve** can be provided by
    - Off-line Generators that are capable of starting, synchronizing, and increasing their output level within ten (10) minutes,
    - Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit that are dispatched as a single aggregate unit that are capable of increasing their output level within ten (10) minutes, and
    - Demand Side Resources, that are supporting their demand reduction through the use of Local Generators and are capable of reducing their Energy usage within ten (10) minutes
- **30-Minute Reserve (spinning and non-synchronized)** can be provided by:
    - Generators, except Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit, that are ISO-Committed Flexible or Self-Committed Flexible and operating within the dispatchable portion of their operating range and
    - Demand Side Resources that are not supporting their Demand Reduction through the use of Local Generation that are ISO-Committed Flexible or Self-Committed Flexible and operating within the dispatchable portion of their operating range, shall be eligible to supply synchronized 30-Minute Reserves.
    - Off-line Generators that are capable of starting, synchronizing, and increasing their output level within thirty (30) minutes

- Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit that are capable of increasing their output level within thirty (30) minutes, and
- Demand Side Resources that are supporting their demand reduction through the use of Local Generators that are capable of starting, synchronizing, and increasing their output level within thirty minutes, shall be eligible to supply non-synchronized 30-Minute Reserves.

- **Self-Committed Fixed and ISO-Committed Fixed Generators** – Shall not be eligible to provide any kind of Operation Reserve.

In Australia (AEMO):

As per the National Electricity Rules (NER) (v86):

If the Market Generator in respect of a generating unit wishes to use that generating unit to provide market ancillary services in accordance with Chapter 3, then the Market Generator must apply to AEMO for approval to classify the generating unit as an ancillary service generating unit.

The provider of FSAS must participate in the market. AEMO is required by NER to:

When AEMO determines the quantity of each market ancillary service which will be enabled, AEMO must determine:

1. *the required quantity of each market ancillary service that may be sourced from any region (referred to as the global market ancillary service requirement); and*
2. *any required quantity of such market ancillary service which must only be sourced from one or more nominated regions (referred to as a local market ancillary service requirement).*

In UK:

STOR services are procured through a tender process. National Grid assesses the resource from a technical perspective before the resource is selected for providing STOR services.

D) How are the markets cleared?

In PJM

The day-ahead scheduling/bidding timeline for PJM energy markets consists of the following time frames:

- At 1030 Hrs— Day-ahead Market bid period closes. All bids must be submitted to PJM. At 1030 PJM begins to run the day-ahead market clearing software to determine the hourly commitment schedules and the LMPs for the Day-ahead Market.
    - The Day Ahead clearing results in the resource commitment profile that satisfies the fixed demand, cleared price-sensitive demand bids, cleared demand reduction bids, and PJM Dayahead Scheduling Reserve (Operating Reserve) objectives, ***while minimizing the total production cost (subject to certain limitations) for energy and reserves.*** This commitment analysis also includes external bilateral transaction schedules and external resource offers into the PJM Day-ahead Market.
- After Day-ahead Results posting-1415 Hrs — PJM opens the balancing market (Real Time Market) offer period. During this time, market participants can submit revised offers for resources not selected in the Day-ahead Market. However if the market participant self-scheduled their unit in the Day-ahead Market, they cannot change the unit status to economic in the rebid period.
- 1415 – The balancing market offer period closes. PJM performs a second resource commitment, which includes the updated offers, updated resource availability information, and updated PJM load forecast information and load forecast deviation. The focus of this commitment is reliability and the objective is to minimize start-up and no load costs for any additional resources that are committed.
- 1415 - Operating Day — PJM may perform additional resource commitment runs, as necessary, based on updated PJM load forecasts and updated resource availability information. PJM sends out individual generation schedules updates to specific generation owners only, as required.
- Generation offers may consist of startup, no-load and incremental energy offer

Intraday Price Discovery

The PJM Real-time Locational Marginal Price (LMP) calculation process consists of several programming modules that are executed as part of the real-time sequence. The real-time sequence executes every five minutes. In the Market Clearing Engine (MCE), the following systems are used in the calculation of the real-time LMP and ancillary service market clearing prices:

- The Real Time Market Applications (Ancillary Service Optimizer (ASO), Intermediate Term Security Constrained Economic Dispatch (IT SCED) and Real-Time Security Constrained Economic Dispatch (RT SCED)
- PJM State Estimator
- Locational Pricing Calculator (LPC)

To conduct the real-time markets, a multi-module software platform is used by PJM to dispatch energy, and ensure adequate reserves in real-time and regulation in near time.

The applications jointly optimize the products on a 5-minute basis to ensure that all system requirements are met using the least cost resource set. The real-time market applications consist of the following:

- **Ancillary Service Optimizer (ASO)**: The Ancillary Services Optimizer (ASO) performs the joint optimization function of energy, reserves and regulation.
    - The ASO creates an interval-based solution over a one hour look-ahead period, as well as performs the regulation three pivotal supplier test.
    - ASO does not calculate market clearing prices.

    - The main functions of ASO are the commitment of all regulation resources and inflexible reserve resources for the next operating hour.
- **Intermediate Term Security Constrained Economic Dispatch (IT SCED)**: The Intermediate Term Security Constrained Economic Dispatch (IT SCED) application is used by PJM to:
        - Perform various functions over a 1-2 hour look-ahead period.
        - anticipate generator performance to various requests, and
        - provide accurate information regarding generator operating parameters under multiple scenarios.
    - The IT SCED solves a multi-interval, time-coupled solution to perform the following functions:
        - Calculate energy dispatch trajectory for use in real-time dispatch
        - Resource commitment recommendations for energy and reserves
        - Resource commitment decisions for economic demand resources
        - Execution of the Three Pivotal Supplier Test (to check market power and prevent its abuse)
- **Real-Time Security Constrained Economic Dispatch (RT SCED)**: The Real-Time Security Constrained Economic Dispatch (RT SCED) application is responsible for dispatching resources to maintain the system balance of energy and reserves. Additionally RT SCED is used to:
    - anticipate generator performance to various requests, and
    - provide accurate information regarding generator operating parameters under multiple scenarios.
    - jointly optimize energy, regulation and reserves on online, dispatchable resources to ensure system needs are maintained.
    - produce energy basepoints and Tier 2 and Non-Synchronized reserve commitments that are sent to resource owners in real-time.
        - All quantities may change with each solution based on system economics and reserve needs.
    - to determine reserves shortages.
- **PJM State Estimator**: The state estimator uses actual operating conditions that exist on the power grid (as described by metered inputs) along with the fundamental power system equations to calculate the remaining flows and conditions that are not metered. The inputs to the state estimator are the available (metered) real-time measurements, the current status of equipment (lines, generators, transformers, etc.), and the bus load distribution factors.
    - The PJM state estimator is run on a thirty-second cycle and can provide the following inputs to the PJM LMP Model, on a five-minute basis:
        - AC power flow solution
        - Actual generator MW output
        - Bus loads
        - Tie line flows
        - MW losses by transmission zone
        - Actual MW flow on any constrained transmission facility
- **Locational Pricing Calculator:** The function of the Locational Pricing Calculator (LPC) is to determine the Real-Time LMP values and Ancillary Service clearing prices on a five minute basis. The LPC is an incremental linear optimization program that is formulated to jointly optimize and price energy and reserves. ***The objective is to minimize the cost function including the cost of energy and reserves subject to the power balance constraint, the Synchronized and Primary Reserve requirements,***

specific generator and demand resource operating limitations, transaction MW limits, and any transmission constraints that currently exist on the system and a normalized distribution of system losses to a network location. **Every 5 minutes the LPC calculates**:

- Locational Marginal Prices (LMPs)
- Synchronized Reserve Market Clearing Prices (SRMCPs)
- Non-Synchronized Reserve Market Clearing Prices (NSRMCPs)
- Regulation Market Clearing Prices (RMCPs) and
- Regulation Market Performance Clearing Price (RMPCP), which are then used to derive the Regulation Market Capability Clearing Price (RMCCP)

In the after-the-fact settlement, any resources cleared as self-scheduled to provide Synchronized Reserve are compensated at the applicable five minute SRMCP. Any pool-scheduled resources selected to provide Synchronized Reserve are compensated at the higher of the applicable five minute SRMCP or their real-time opportunity cost plus their Synchronized Reserve offer price.

<u>In NYISO</u>

Security Constrained Unit Commitment (SCUC) commits generation and produces Day Ahead Market (DAM) schedules for the co-optimization of energy, reserves and regulation. The mechanism proposed for India comes close to the extant mechanism in NYISO. Key features of this market are characterised below:

- Full two-settlement Markets: in DAM through SCUC and in real time through Real Time Dispatch (RTD)).
- Day Ahead schedules are financially binding
- In the DAM, Resources capable of providing Spinning Reserve, 10-Minute Non-Synchronized Reserve, and/or 30-Minute Reserve (spinning and non-synchronized) in the Day-Ahead commitment may submit Availability Bids for each hour of the upcoming day.
- The NYISO shall select Operating Reserve Suppliers for each hour of the upcoming day through a ***co-optimized Day-Ahead commitment process that minimizes the total cost of Energy, Operating Reserves, and Regulation Service, using Bids submitted to the NYISO.*** As part of the cooptimization process, the NYISO shall determine how much of each Operating Reserves product particular Suppliers will be required to provide in light of the Reliability Rules and other applicable reliability standards, including the locational Operating Reserves requirements
- Suppliers that are scheduled Day-Ahead to provide Operating Reserves shall either provide Operating Reserve, or Energy, or, when the NYISO has the capability to support demand side participation, reduce demand in Real-Time when scheduled by the NYISO in all hours for which they have been selected to provide Operating Reserve and are physically capable of doing so.
    - ***Suppliers that are scheduled Day-Ahead to provide Operating Reserves and have startup periods of two hours or less may advise the NYISO no later than three hours prior to the first hour of their***

Day-Ahead schedule that they will not be available to provide Operating Reserves or Energy in Real-Time under normal conditions.

- ***Such Suppliers will be required to settle their Day-Ahead schedule at Real-Time prices.*** The only restriction on Suppliers' ability to exercise this option is that all Suppliers with Day-Ahead Operating Reserves schedules must make the scheduled amount of Capacity available to the NYISO for dispatch in the RTD if the NYISO initiates a Supplemental Resource Evaluation.

- The NYISO will automatically select Operating Reserves Suppliers in Real-Time from eligible Resources. All Suppliers will automatically be assigned a Real-Time Operating Reserves Availability bid of $0/MW.
- ***Suppliers are selected, in Real Time, based on their response rates, their applicable upper operating limit, and their Energy Bid (which will reflect their opportunity costs) through a co-optimized Real-Time commitment and dispatch process that minimizes the total cost of Energy, Regulation Service, and Operating Reserves.*** As part of the process, the NYISO shall determine how much of each Operating Reserves product particular Suppliers will be required to provide in light of the Reliability Rules and other applicable reliability standards, including the locational Operating Reserves requirements
    - Reserves selected in the DAM must buy back what is not scheduled in RT, at the RT clearing price. Suppliers that are scheduled Day-Ahead to provide Operating Reserves and have start-up periods of two hours or less may advise the NYISO no later than three hours prior to the first hour of their Day-Ahead schedule that they will not be available to provide Operating Reserves or Energy in Real-Time under normal conditions. Such Suppliers will be required to settle their Day-Ahead schedule at Real-Time prices.
        - The only restriction on Suppliers' ability to exercise this option is that all Suppliers with Day Ahead Operating Reserves schedules must make the scheduled amount of Capacity available to the NYISO for dispatch in the Real Time Dispatch if the NYISO initiates a Supplemental Resource Evaluation.
    - This mechanism eliminates additional costs in real time market due to re-optimization or procurement of replacement services in RT and creates additional incentive for suppliers to be available in RT and to perform when called upon in a reserve activation.
    - Reserve clearing price in Real Time Dispatch
        - Real Time reserve is scheduled and dispatched very five minutes based on co-optimization of energy, reserves and regulation over next one hour
        - Reserve clearing prices in real time are set using the concept of shadow pricing – the shadow prices of the various "nested" reserves – for example, availability of a 10 minute reserve

would impact the "shadow" price or "opportunity" cost of a 30 minute reserve. Shadow price is essentially the locational opportunity cost of resource proving the reserve at the margin

- Locational Demand Curves are declared by the System Operator
    - Price of Reserves is defined even if not enough reserves are available at any price to meet the ISO's reserve target.
    - In shortage (Capacity Constrained) situations, the price of reserves is set by the Demand Curve.
    - Only MWs scheduled as reserves are paid the reserve clearing price
    - Demand Curve creates a risk on the supplier of pricing themselves out of the market.
    - Demand Curve values were set high enough to capture with a high degree of certainty, all available reserve
    - In case of emergent situations the system operator can manually procure reserves to meet the requirements

<u>In Australia (AEMO):</u>

- Under the National Electricity Market (NEM) frequency standards AEMO must ensure that, following a credible contingency event, the frequency deviation remains within the contingency band and is returned to the normal operating band within five minutes. Participants must register with AEMO to participate in each distinct Frequency Control Ancillary Services (FCAS) market. Once registered, a service provider can participate in an FCAS market by submitting an appropriate FCAS offer or bid for that service, via AEMO's Market Management Systems. An FCAS offer or bid submitted for a raise service represents the amount of MWs that a participant can add to the system, in the given time frame, in order to raise the frequency. An FCAS offer or bid submitted for a lower service represents the amount of MWs that a participant can take from the system, in the given time frame, in order to lower the frequency. ***<u>During each and every dispatch interval of the market, National Electricity Market Dispatch Engine (NEMDE) must enable a sufficient amount of each of the eight FCAS products, from the FCAS bids submitted, to meet the FCAS MW requirement.</u>*** NEMDE enables MW FCAS offers in merit order of cost. The highest cost offer sets the marginal price for the FCAS category. During periods of high or low demand, it may be necessary for NEMDE to move the energy target of a scheduled generator or load in order to minimise the total cost (of energy plus FCAS) to the market. This process is named co-optimisation and is inherent in the dispatch algorithm. (Ref: https://www.aemo.com.au/-/media/Files/PDF/Guide-to-Ancillary-Services-in-the-National-Electricity-Market.pdf).
    - Registered generators provide offers for each FCAS service every five minutes in conjunction with their energy offers. The nine markets (eight

FCAS services and the single energy service) are fully co-optimised on the single real-time (five minute) platform.

- All offers can be revised up to the five minute interval immediately preceding dispatch.
- Regional half-hourly clearing prices (the time weighted average of the six five minute prices) are set for each of the FCAS markets based upon the marginal value of the service.
- Participants in the FCAS markets are procured and the market price set according to AEMO's determined requirement for each service capability in that five minute period.
- FCAS providers are paid regardless of whether this capability is actually called upon over that period. This differs from the wholesale energy spot market where generators are only paid according to their actual dispatch.

In UK:

- Short Term Operating Reserves (STOR), which are provided over the same duration (delivery needs to be within 20 minutes), can be provided by either generation or demand assets.
- The minimum volume required is 3 MW, which can be provided from either a single site or an aggregation of sites – approximately 20% of STOR volume is contracted via an aggregator.
- Delivery needs to be within 20 minutes of instruction and should be able, if needed, to maintain full output for at least two hours.
- Procurement is via a competitive tender process with services being provided on either a committed or flexible basis, with three tender rounds per year. (Reference: Ancillary Services Report 2017, Published by Energy UK, Available at: https://www.energy-uk.org.uk/publication.html?task=file.download&id=6138). National Grid holds three competitive tenders each year for the STOR service. Providers submit their prices for availability and utilisation during these tenders.
  - Value and costs of each submitted tender is compared with the economic costs of procuring the same volume of reserve from alternative sources.
  - In addition, National Grid may also consider a number of other factors, including the historic reliability and geographical location of a unit or site.
  - There is limited information available regarding the basis on which the tenders are assessed. It is expected that by the second quarter of 2018 contract terms for Fast Reserve standardised and STOR products will be divided into two classes according to ramp-up times. National Grid will then launch a new web-based platform for ancillary services over the summer, initially supporting the Fast Reserve market before being rolled out to the STOR market later in the year. These changes are expected to

increase competition in the market. ***The intention is to move to day ahead auction as quickly as possible as the same is expected to reduce costs and provide generators with a better opportunity of revenue stacking.***

E) How are the services charged for?

In PJM:

- The total cost of Day-ahead Operating Reserve for the Operating Day is allocated and charged to PJM Members ***in proportion to their total cleared day-ahead demand and decrement bids plus their cleared day-ahead exports for that Operating Day.***
- The total cost of Balancing Operating Reserve for the Operating Day is allocated and charged to PJM Members ***in proportion to their locational real-time deviations from day-ahead schedules and generating resource deviations during that Operating Day, or to PJM Members in proportion to their real-time load plus exports during that Operating day for generator credits provided for reliability***

In NYISO

Transmission Customers and Customers engaging in Export Transactions and LSEs pay an hourly charge equal to the product of:

a. the cost to the ISO of providing all Operating Reserves for a given hour; and
b. the ratio of (i) the LSE's hourly Load or the Transmission Customer's hourly scheduled Export Transactions, to (ii) the sum of all Load in the NYCA and all scheduled Export Transactions

The cost to the ISO of providing Operating Reserves in each hour will equal the total amount that the ISO pays to procure Operating Reserves on behalf of the market in the Day-Ahead Market and the Real-Time Market, less payments collected from entities that are scheduled to provide less Operating Reserves in the Real-Time Market than in the Day-Ahead Market during that hour.

In Australia (AEMO):

- As contingency raise requirements are set to manage the loss of the largest generator on the system, all payments for these three services are recovered from generators.
- As contingency lower requirements are set to manage the loss of the largest load / transmission element on the system, all payments for these three services are recovered from customers.
- Recovery for contingency services is pro-rated over participants based on the energy generation or consumption in the trading interval.

In UK:

All Generators and Suppliers connected with the transmission system are liable for Balancing Services Use of System charges based on their energy taken from or supplied to the National Grid system in each half-hour Settlement Period.