CENTRAL ELECTRICITY REGULATORY COMMISSION
NEW DELHI

Draft Central Electricity Regulatory Commission (Ancillary Services) Regulations, 2021

EXPLANATORY MEMORANDUM

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1. Introduction

1.1 Ancillary services are an indispensable part of the power system operation, which are required for improving and enhancing reliability of the power system. One of the important components of ensuring grid reliability includes achieving adequacy of reserves and maintaining the load-generation balance.

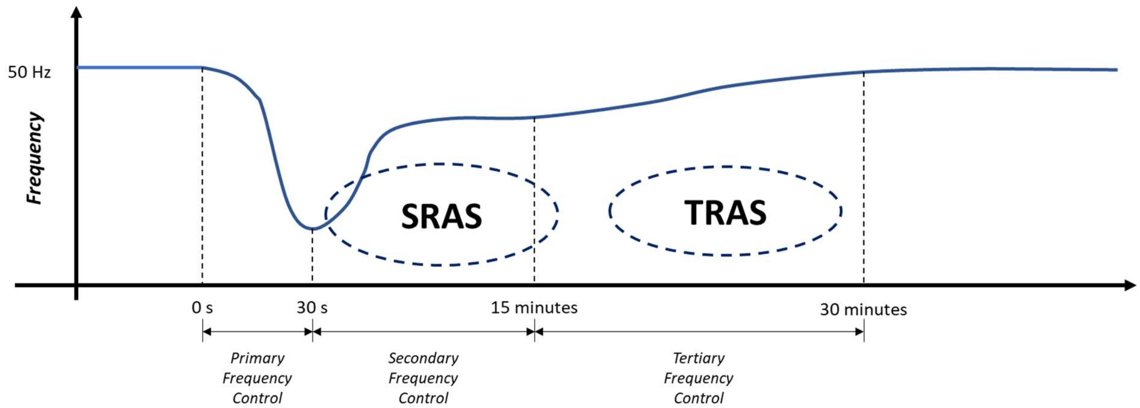
1.2 The National Electricity Policy (NEP) mandates that adequate reserves may be maintained to ensure secure grid operation:

> "*5.2.3 In order to fully meet both energy and peak demand by 2012, there is a need to create adequate reserve capacity margin. In addition to enhancing the overall availability of installed capacity to 85%, a spinning reserve of at least 5%, at national level, would need to be created to ensure grid security and quality and reliability of power supply*."

1.3 Ancillary Services may include a number of different operations such as frequency support through primary control, secondary control and tertiary control; voltage support; and system restoration. Primary control generally refers to local automatic control available in all conventional generators, which delivers reserve power negatively proportional to frequency change. Such immediate automatic control is implemented through turbine speed governors, in which the generating units respond quickly to the frequency deviation as per droop characteristic of the units. Secondary control involves automatic control signals like Automatic Generation Control (AGC) which delivers reserve power in order to bring back the frequency and the interchange of the control area to their target values. Tertiary control refers to manual change in the despatch, or drawal and unit commitment in order to restore the secondary reserve, as loss of generator or loss of demand may cause a system contingency.

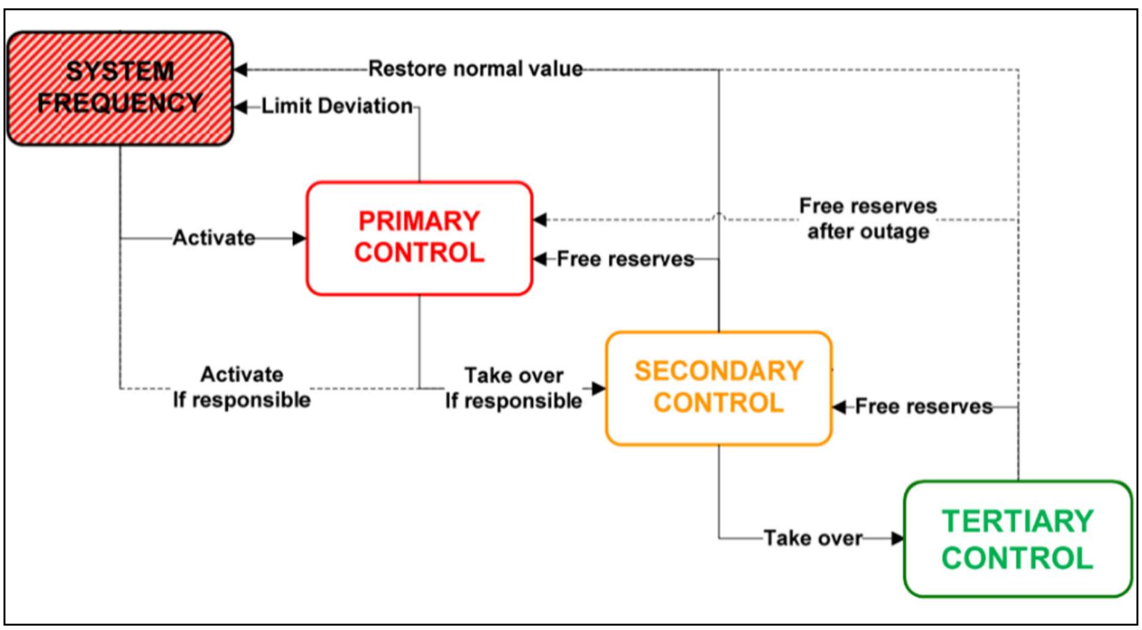
1.4 Primary reserves respond to frequency signals, typically, within 5-10 seconds and sustain upto 5 minutes. Primary reserves aim at stabilizing the system frequency post contingency. The secondary reserves are automatic or deployed online by the system operator to relieve the primary reserve and restore frequency back to its nominal value. Secondary reserves respond in 30 seconds and ramp up their full output within 15 minutes and can sustain upto at least next 30 minutes, if required. Tertiary reserves are deployed to relieve the secondary reserves and is generally activated within 15 minutes from the despatch instructions. This has been illustrated in Figure 1 and Figure 2 below.

Figure-1: Activation and Deployment of Ancillary Services



Source: CERC Staff

Figure-2: Schematic of activation and deployment of reserves (frequency control)



Source: *http://www.forumofregulators.gov.in/Data/Reports/SANTULAN-FOR-Report-April2020.pdf*

1.5 The Electricity Act, 2003 entrusts upon the Commission important responsibilities inter alia of regulating the inter-State transmission of electricity, specifying the Grid Code and also enforcing standards with respect to quality, continuity and reliability of service by licensees. Laying down of framework for effective and secure grid operation is thus one of the most important mandates of the Commission. The Commission has a taken number of initiatives towards this end.

1.6 The responsibility of the power system operators is to maintain stability and reliability of the power system. For a large complex grid such as the Indian grid, primary, secondary and tertiary frequency control are must-have tools to ensure stability of the power system.

1.7 The Commission through its Order dated 13.10.2015 provided a roadmap to operationalise reserves in the country. The primary reserves have been ensured through suitable amendments in the Grid Code which require the generating stations to keep such reserves for system security, by not scheduling beyond their installed capacity. For secondary reserves , the Commission has taken phased approach by implementing pilots with a few ISGS(inter-State Generating Stations) and subsequently directing vide Order dated 28.08.2019 in Petition No. 319/RC/2018 that all inter-State generating stations (ISGS) should be AGC enabled. As regards tertiary control, the Central Electricity Regulatory Commission (Ancillary Services Operations) Regulations, 2015 (in short, 'the RRAS Regulations') have been in operation since 2015.

Table-1: Existing Regulatory Provisions for Ancillary Services in India

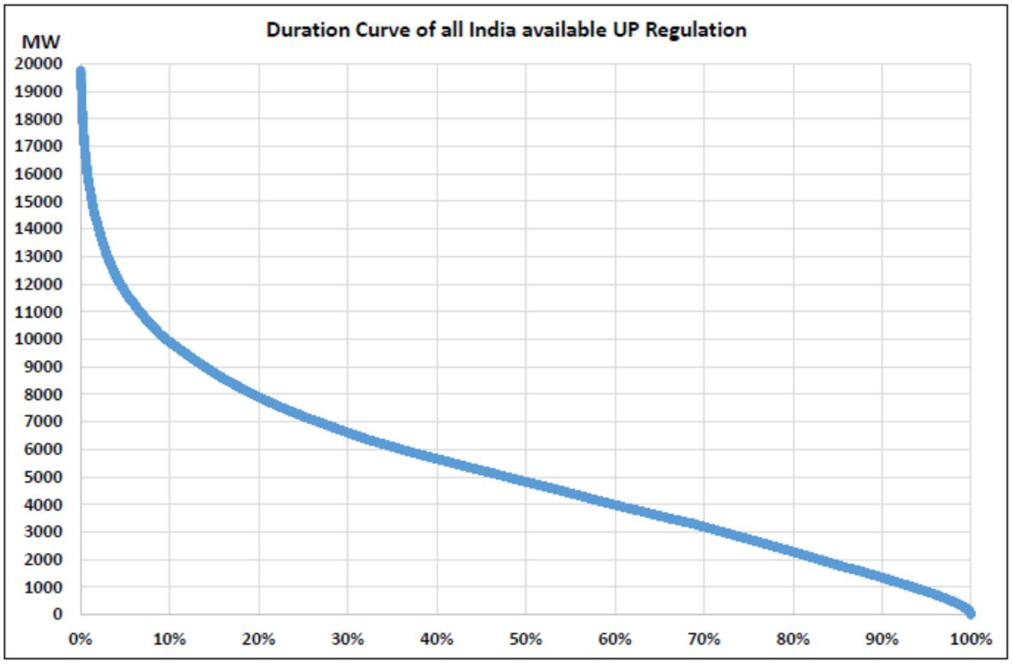
Type of Service	**Outline**	**Response Time**	**Current Status**
Primary response (Frequency Containment)	Automatic response delivering reserve power in negative proportion to grid frequency change	Few seconds (able to sustain upto 5 min)	Mandated through the Grid Code ***Clause 5.2(h) of the Grid Code states:-*** ***Coal / lignite stations> 200 MW, Gas stations >50 MW and hydro >25 MW operating at or up to 100% MCR shall normally be capable of picking up to 105/ 105/ 110% respectively of MCR when frequency falls suddenly*** ***Generating station/ unit not to be scheduled beyond 100% IC***
Secondary response (Frequency Restoration)	Supplementary corrective action needed to bring frequency back to 50 Hz.	30 s (able to sustain upto at least 15 minutes)	CERC Order dated 28th August 2019 in Petition No 319/RC/2018, on AGC for ISGS.

Tertiary response	All ISGS including Ultra Mega Power Plants (UMPPs), operating on part load and having URS availability on day ahead basis	Within 15 minutes (able to sustain upto 60 minutes)	Implemented under administered mechanism since 2016 as per the RRAS Regulations

1.8 The RRAS Regulations primarily cater to slow tertiary reserves using the un-requisitioned surplus (URS) in the generating stations that are regional entities and whose tariff is determined or adopted by the Commission for their full capacity. A mark-up is provided over and above the variable charge of the service provider to encourage the individual participants to provide these services. While this framework has served well by setting the context of reserves and ancillary services in the Indian power system, a need has been felt to bring about design changes in the existing system in view of the following challenges: -

- Availability of adequate reserves during periods of high demand cannot be ascertained. Extant the RRAS Regulations uses only the un-scheduled component of capacity of the regional generators whose tariff for the full capacity is determined or adopted by the Commission. Out of this fleet of generating stations, only the reserves left over in the on-bar machines are available for despatch as RRAS. As depicted in Figure-3, in the year 2019-20, Up reserves were available around 60%-70% of the time. In other words, 30-40% of the time, Up reserves were not available.
- It has been observed that Ancillary Services have been used for multiple hours with the objective of meeting morning demand. A clear distinction needs to be drawn between ancillary service and balancing demand and supply through energy markets.
- Ancillary Services are needed to maintain power system frequency within the allowable band as per the Grid Code. 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 current mechanism of RRAS does not consider the accuracy of the delivery within that period.

Figure-3: Availability of reserves in 2019-20



Source: POSOCO presentation on Secondary Reserve to the Commission

1.9 As regards Secondary Reserves, the Commission vide Order dated 28.08.2019 in Petition No. 319/RC/2018 has directed that all Inter-State Generating Stations (ISGS) should be AGC enabled. Post the directive of the Commission, a total of 94 ISGS covering more than 85 GW installed capacity are expected to be brought under AGC. Furthermore, all the upcoming power plants would be AGC compliant. Valuable experience has been gained in terms of implementation aspects, communication protocols, generator regulation and load following capabilities, cyber security etc. which is useful for implementation of secondary reserves on a large scale. The Commission observes that the feedback on implementation of AGC submitted by POSOCO highlights the need for enhancing adequacy of reserves in the country.

1.10 The existing framework of Ancillary Services predominantly utilises the thermal power stations which have ramping limitations and as such there is a need for a fast response ancillary service. The fast response reserves become all the more essential in view of the increasing penetration of intermittent renewable energy sources. The present administered mechanism of RRAS cannot accommodate such resources, especially the new and emerging technologies/ resources like energy storage and demand side response. The Commission observes that given the changes in technology, generation mix and increasing decentralized generation, and location specific requirements for ancillary services, there is a need for a comprehensive framework of Ancillary Services.

1.11 In this context, the staff of the Commission brought out a discussion paper on *Re-designing Ancillary Services Mechanism in India* in September, 2018 highlighting the need for and proposing inter alia market-based mechanism for procurement of Ancillary Services so as to enlarge the ambit of potential providers of such services. Further, the Commission in its Order dated 28.08.2019 in Petition No 319/RC/2018 directed the staff of the Commission to initiate a comprehensive review of Ancillary Services framework and present to the Commission for suitable decision.

1.12 In the backdrop of the above, the Commission based on review of the emerging market conditions especially in view of the current and projected level of penetration of intermittent renewable energy generation resources in the country, has felt the need for a comprehensive regulatory framework on Ancillary Services and accordingly has placed the draft Central Electricity Regulatory Commission (Ancillary Services) Regulations, 2021 (in short, 'the draft Ancillary Services Regulations') for public consultation.

2. Salient Features of the Draft Ancillary Services Regulations

2.1 The draft Ancillary Services Regulations provide measures for maintaining grid frequency within allowable band and for relieving transmission congestion to support reliable and stable operation of the grid, besides procurement and commercial mechanism for Secondary Reserve Ancillary Services (SRAS) and Tertiary Reserves Ancillary Services (TRAS). The Ancillary Services other than SRAS and TRAS shall be governed by the Grid Code or as specified by the Commission separately.

2.2 The draft Ancillary Services Regulations mandate the requirement of estimation of SRAS and TRAS by the Nodal Agency (NLDC). SRAS is proposed to be procured through an administered mechanism to start with. However, there is an enabling provision for market-based procurement of SRAS, the framework for which can be specified separately by the Commission based on review of the operation of SRAS. TRAS is proposed to be procured through market-based mechanism.

2.3 The ambit of participation is proposed to be expanded by including the generating stations connected to inter-State transmission system or intra-State transmission system, energy storage and demand side resources meeting the specified eligibility conditions.

2.4 The draft Ancillary Services Regulations seek to reward fast ramping resources in the SRAS segment. SRAS would be signalled for despatch based on the ramp rates and variable/ compensation charges. Thus, resources with higher ramping rates and lower variable/ compensation charges would have a higher probability of getting despatched. Apart from payment for the energy delivered, the SRAS Providers would also be eligible for performance-based incentive.

2.5 TRAS is proposed to be procured through market-based mechanism. A separate Ancillary Service product is to be introduced in the existing Day Ahead Market and Real Time Market. For TRAS-Up, the principle of uniform market clearing price (MCP) has been proposed. However, for TRAS-Down, the pay-as-you-bid mechanism has been adopted. TRAS-Up cleared but not despatched would be given commitment charge at 10 percent of the MCP for TRAS-Up subject to the ceiling of 20 paise/kWh.

2.6 The draft Ancillary Services Regulations also provide for measures in case of shortfall of SRAS and TRAS procurement and in case of emergency conditions.

2.7 The Commission has recognised the following types of Ancillary Services namely,

(a) Primary Reserve Ancillary Service (PRAS);
(b) Secondary Reserve Ancillary Service (SRAS);
(c) Tertiary Reserve Ancillary Service (TRAS); and
(d) Such other Ancillary Services as specified in the Grid Code

The draft Regulations cover SRAS and TRAS and stipulate that PRAS and other Ancillary Services shall be governed by the Grid Code or as specified separately by the Commission.

3. Estimation of Reserves by the Nodal Agency

3.1 The starting point of securing adequate reserves in the system is the estimation of reserves requirement. The draft Ancillary Services Regulations mandate estimation of the SRAS and the TRAS requirement by the Nodal Agency (NLDC). The methodology of estimation of SRAS and TRAS shall be stipulated in the Grid Code. The report submitted by the Expert Group on review of the Grid Code has suggested a methodology for estimation of secondary and tertiary reserves. The Report is under consideration of the Commission. Until methodology for estimation of secondary and tertiary reserves is specified, the Nodal Agency is required to stipulate the estimation criteria in the Detailed Procedure. Estimation of reserves would be done on a longer time horizon. However, the Nodal Agency shall re-assess the quantum of requirement of SRAS and TRAS on day-ahead basis and also on real time basis.

3.2 Secondary reserves are required to be maintained to manage the area control error of a region. Accordingly, the requirement of SRAS shall be estimated on regional basis by the Nodal Agency.

4. Secondary Reserves Ancillary Service (SRAS)

Eligibility for SRAS Provider

4.1 SRAS Providers must have the necessary infrastructure set up so that they can receive and respond to automatic secondary control signal sent by the Nodal Agency. SRAS is fast response service and hence SRAS providers should be capable of responding to SRAS signal within 30 seconds and providing the entire SRAS capacity obligation within fifteen (15) minutes and sustaining at least for the next thirty (30) minutes. The SRAS provider should also be capable of providing at least 1 MW of secondary response.

4.2 Secondary Reserve resources should have fairly fast and accurate response rates to adjust output quickly to changing signals. Generating stations participating in the SRAS segment should be AGC enabled. Any resource participating in SRAS should have bidirectional communication system with the Nodal Agency along with SCADA telemetry in place for monitoring and measurement of energy delivered under SRAS. This is an important requirement to ensure that SRAS providers can respond to every four seconds secondary control signals provided by the Nodal Agency.

4.3 Several countries have allowed energy storage and demand side resources to provide secondary and even primary reserves, recognising their ability to follow secondary control signal faster and more accurately. Even though Indian power sector does not have experience of using such resources as reserve services as of now, the Commission has felt it expedient to create enabling framework for such resources to participate as Ancillary Service providers. This will not only help manage the system imbalances better but will also give fillip to develop market for such resources in the long run. It is envisaged that Demand Response would facilitate participation of the end customers directly or through aggregators in the Ancillary Services segment. The Nodal Agency is expected to prepare the required technical and operational criteria for enabling such resources to participate as AS providers.

Activation and Deployment of SRAS

Secondary reserves are deployed primarily to correct the Area Control Error (ACE). The draft Ancillary Services Regulations provide that ACE for each region would be auto calculated at the Nodal Agency control centre for this purpose based on the telemetered values, and the external inputs like meter errors. Area Control Error (ACE) for a region will be calculated as follows:

$$ACE = (I_a - I_s) - 10 * B_f * (F_a - F_s) + Offset$$

Where,

I_a = Actual net interchange in MW (positive value for export)

I_s = Scheduled net interchange in MW (positive value for export)

B_f = Frequency Bias Coefficient in MW/0.1 Hz (negative value)

F_a = Actual system frequency in Hz

F_s = Schedule system frequency in Hz

Offset = Provision for compensating for metering and measurement error

4.4 Positive ACE implies over-generation and it causes interconnection frequency to rise while a large negative ACE implies under-generation and it causes interconnection frequency to drop. Frequency Bias means control area's response to an interconnection frequency error, typically expressed in megawatts per 0.1 Hz (MW/0.1 Hz). The Nodal Agency estimates Frequency Response Characteristic for each region and refines the same from time to time. The median Frequency Response Characteristic estimated during previous financial year of each region, should become the basis for calculating Frequency Bias Coefficient (B_f) for calculating the ACE for any region. Schedule System Frequency in above ACE formulation is nothing but the reference Frequency of 50 Hz. The Nodal Agency would formulate the procedure for Offset in consultation with RLDCs and SLDCs.

4.5 Any control system for stable operation needs a small dead band as large dead band would make the system control ineffective. Hence, the Commission has proposed dead band of ±10 MW for activation of SRAS as proposed by the Expert Committee on the review of the Grid Code. Further, the Commission will stipulate other events for activation of secondary response in the system as and when the Commission reviews the Grid Code.

4.6 As informed by the Nodal Agency, the software implemented by the Nodal Agency for SRAS is capable of operating in any of the three control modes viz., tie-line bias mode, flat frequency mode or flat tie-line mode. Accordingly, the Nodal Agency may operate SRAS in any of the three control modes depending on grid requirements.

Procurement of SRAS

4.7 As mentioned above, secondary response is deployed to maintain frequency within allowable band and restore frequency close to 50Hz as early as possible. It needs to respond to second to second variation in ACE of a region.

4.8 Under the proposed mechanism for procurement, SRAS providers are required to provide standing consent to the Nodal Agency for participation. This standing consent would remain valid till it is modified or withdrawn. However, it cannot be modified or withdrawn without giving notice of forty-eight hours to the Nodal Agency. This would provide sufficient time for the Nodal Agency to make required changes for allocating secondary control signal to such generators without frequent changes in the software. This would also help in assessing the availability of secondary reserves properly.

4.9 In view of the fact that secondary reserves are deployed automatically for quick response, it is necessary that relevant technical and commercial parameters are fed into the software at Nodal Agency for effective and efficient implementation of SRAS. Accordingly, generating stations, which are participating in the SRAS, shall provide technical parameters such as installed capacity, technical Minimum, ramp up and ramp down capability, prohibited zones for hydro stations, etc. in such time interval as may be stipulated in the Detailed Procedure by the Nodal Agency. Other SRAS Providers like energy storage, demand side response also need to provide required technical parameters as stipulated in the Detailed Procedure by the Nodal Agency.

4.10 SRAS providers shall also declare their variable charge (for generating stations) or compensation charge (for energy storage and demand side resource) upfront on monthly basis in the manner as stipulated in the Detailed Procedure. This charge would be considered by the Nodal Agency for despatching the SRAS. No retrospective revision of such charges would be allowed at the time of payment and settlement for SRAS providers.

4.11 In order to ensure that adequate secondary reserves are available in the system, the Commission has proposed that the Nodal Agency shall ascertain availability of adequate reserves on day-ahead basis and on real-time basis from the SRAS providers that are willing to participate in the SRAS.

4.12 Further, considering the existing practice of scheduling and despatch, it would be important to continually assess the availability of the secondary reserves in the system to take care of any contingency or system imbalance. Accordingly, the Commission has proposed that in case of the generating stations whose tariff is determined by the Commission under Section 62 of the Act, the Nodal Agency shall identify the generating stations for providing SRAS, on day-ahead basis, based on the capacity available after the schedule has been communicated at 2300 hrs for the next day and on real-time basis before the gate closure.

Selection of SRAS Providers and Despatch of SRAS

4.13 SRAS is proposed to be selected and despatched on regional basis. Depending on the values of ACE, secondary reserves would provide SRAS-Up or SRAS-Down service. For SRAS-Up, a generating station or energy storage providing SRAS shall increase its active power injection, while demand side response providing SRAS would decrease its drawal or consumption. Similarly for SRAS-Down, a generating station or energy storage providing SRAS shall decrease its active power injection, while demand side response providing SRAS would increase its drawal or consumption.

4.14 For secondary response, SRAS Providers would be controlled automatically via 4-second secondary control signals from the Nodal Agency, without any manual intervention and SRAS provider would allow its control centre to follow secondary control signal accordingly for providing SRAS-Up and SRAS-Down. Accordingly, the SRAS Provider, would either increase or decrease its generation if it is a generating station or increase or decrease its drawal or consumption if its not a generating station. The Detailed Procedure would cover the modalities of communication between Nodal Agency and SRAS Providers for effective and efficient communication system.

4.15 Secondary control signals would be transmitted and received at 4 second interval between the control centre at NLDC and the control centre at SRAS Provider. The relevant data would be stored at both ends. The Nodal Agency would reconcile these two datasets to take care of gaps arising due to communication failure etc. SRAS Provider needs to share real-time data with the Nodal Agency as stipulated in the Detailed Procedure which would then be reconciled by the Nodal Agency for post facto accounting and performance measurement.

4.16 Based on the requirement of SRAS in a region, SRAS would be selected using Custom Participation Factor. SRAS Providers would be selected for SRAS-Up and SRAS-Down, as the case may be, on regional basis. The primary objective of introducing custom participation factor is to incentivise faster and dynamic resources while at the same time ensuring that such resources are deployed at the most optimal cost. Accordingly, the Nodal Agency would take into account the following criteria for determination of Custom Participation Factor for each SRAS Provider:

a. Rate Participation Factor (Ramping capability in MW/min)

b. Cost Factor (variable charge or compensation charge, as the case may be)

4.17 Each of the aforesaid factors would be normalized by taking ratio of the respective factor of the SRAS Provider to the total value of the said factor for all SRAS Providers. This is aimed at assigning relative weightage to an SRAS Provider vis a vis other SRAS Providers. The Custom Participation Factor for SRAS-Up shall be directly proportional to the normalized Rate Participation Factor and inversely proportional to the normalized Cost Factor. The Custom Participation Factor for SRAS-Down shall be directly proportional to the product of the normalized Rate Participation Factor and normalized Cost Factor.

4.18 Based on the above principles, Custom Participation Factor shall be calculated which shall be normalised to determine the participation of each SRAS Provider.

4.19 SRAS signal shall be allocated among the SRAS Providers to meet SRAS requirement of the system based on the normalised Custom Participation Factor subject to the ramp limited resources available with the SRAS Provider(s). A simple illustration in this regard has already been provided in the draft Ancillary Services Regulations as Appendix-I.

4.20 The Commission feels that an energy settlement system based on 5- minute time block is likely to bring in better granularity in grid management and ramp monitoring. However, as per existing energy settlement system, procedure of log records is based on 15-minute time block. Logging of MW signals over 5 minutes in MWh would be possible only after up-gradation of the presently available metering system of 15-minute time blocks to 5-minute blocks. Till that time one 15-minute time block can be assumed as three 5-minute time sub-blocks. Hence, the Commission has proposed to adopt the same methodology of recording and measurement of secondary control signals as was used in the implementation of AGC pilot with a few selected ISGS.

4.21 Further, since the SRAS is a MW regulation service and no energy meter can capture secondary control signal in 4 seconds, SRAS accounting should be done based on SCADA data. The Commission also observed during the AGC pilot that SCADA software has features of recording and aggregating the secondary control signal (of 4 seconds) for every five minutes. Thus, sufficient experience has been gained regarding measurement aspects of secondary control signal through SCADA and Energy Management System under AGC pilot.

Payment for SRAS

4.22 Accounting of secondary reserves would require 5 minutes MWh and 15 minutes MWh data. Incentive for SRAS provider would be calculated using average values of aggregated 5 minutes data, while energy would be computed using average values of 15-minute data for SRAS. It would be important to note that 5-minute MWh data would be calculated in absolute terms to capture both SRAS-Up and SRAS-Down service, while 15-minute data would be net of SRAS-Up and SRAS-Down. For this purpose, the archived SCADA data at the Nodal Agency shall be reconciled with the data received at control centre of the SRAS Provider.

4.23 For net SRAS-Up energy computed over 15-minute time block, SRAS Provider would be paid from the Deviation and Ancillary Service Pool Account, at the rate of their variable charge or compensation charge, as the case may be, as declared by the SRAS Provider. For net SRAS-Down energy computed over 15-minute time block, SRAS Provider would pay back to Deviation and Ancillary Service Pool Account, at the rate of their variable charge or compensation charge, as the case may be, as declared by the SRAS Provider.

Performance of SRAS Provider and incentive

4.24 SRAS Providers would be eligible for incentive based on the performance measured by the Nodal Agency. Methodology for performance measurement of SRAS provider has been detailed in the draft Ancillary Services Regulations in Appendix-II.

4.25 For each SRAS Provider, the Nodal Agency would derive a scatter X-Y plot by comparing the actual response provided by the SRAS Provider against the secondary control signal sent every 4 seconds on post-facto basis using SCADA data for each day. Based on this performance, each SRAS provider would be eligible for incentive rate corresponding to its performance measurement. If the performance of an SRAS Provider is above 95% in a day, it would be eligible for incentive rate of 40 paise per unit. If the performance is between 70% to 95%, the SRAS provider would be eligible for incentive rate of 30 paise per unit and so on. The following table gives incentive rates for different levels of performance of SRAS Provider:

Table-2: Incentive rates against Actual Performance of SRAS Provider

Actual performance vis-à-vis SRAS signal for an SRAS Provider	Incentive Rate (+) (paise/ kWh)
Above 95%	(+) 40
70-95 %	(+) 30
45-70%	(+) 20
20-45%	(+) 10
Below 20%	0

4.26 SRAS is being introduced for the first time in India. As such, the Commission has proposed to take liberal approach by allowing incentive upto 20% performance of SRAS provider. Further, since payment of variable charges is based on average of SRAS-Up and

SRAS-Down for 15 minutes, there could be a situation where an SRAS Provider despite having participated in SRAS might have contributed zero MWh during any specific 15-minute time block, which would mean no payment of variable charge for such SRAS Provider. However, even in such a situation, the SRAS Provider shall be entitled to incentive, which is meant to recognize and reward the performance irrespective of the energy delivered by the SRAS Provider. As a deterrent, it has been provided that performance below 20% for two consecutive days by an SRAS Provider would make the SRAS Provider liable for disqualification for participation in SRAS for a week.

5. Tertiary Reserve Ancillary Service (TRAS)

Eligibility for TRAS Provider

The existing framework of RRAS uses the generating stations that are regional entities and whose tariff is determined or adopted by the Commission for their full capacity to provide Ancillary Services. However, these generating stations can be recalled by the beneficiaries that have paid the capacity charges for their capacity share in these generating stations. This lends uncertainty in terms of availability of "reserves" in the existing system. Therefore, in order to ensure availability of resources on a firm basis and with a view to enlarging the ambit, the draft Ancillary Services Regulations make any generating station, energy storage or demand side resource eligible for participation as TRAS Provider if it is capable of varying its active power output or drawl or consumption as per the instruction from the Nodal Agency within 15 minutes and sustaining the service for at least next 60 minutes.

Activation and Deployment of TRAS

5.1 Tertiary reserve provides insurance against widespread outages. Loss of large generator (or load) may cause a large enough system excursion that cannot be handled by secondary reserve alone and in addition the secondary reserves need to be restored through tertiary reserves.

5.2 While secondary reserves would be deployed to correct ACE, it is necessary to release such secondary reserves for any subsequent event. As such, the draft Ancillary Services Regulations provide that the tertiary reserves would be activated if secondary reserve has been deployed continuously in one direction for fifteen (15) minutes for more than 100 MW, in order to replenish the secondary reserve. Other activation criteria for tertiary reserves would be as specified in the Grid Code.

Procurement of TRAS

5.3 The mechanism for procurement of Ancillary Services should be such as to ensure that there are no barriers to entry and exit and the system operator should be able to access the most flexible technology at the most optimum cost. It is equally important that the mechanism has inbuilt incentive mechanism to enlist interest of the market participants in offering their services. It is with this objective in mind that the procurement strategy for TRAS has been provided in the draft Ancillary Services Regulations. Procurement of Tertiary Reserves is proposed to be market-based with a provision for commitment charge for the capacity procured but not despatched.

5.4 It has been proposed that the Nodal Agency shall communicate the quantum of procurement of TRAS Up and TRAS Down to the power exchanges without any price offer attached with the same. The Nodal Agency shall communicate such requirement before the commencement of the day-ahead market window in the power exchange. This would form the buy bid in the power exchange against which power exchanges would solicit sell bids from the TRAS providers as separate product – separate from energy product. The Commission has provided another opportunity to the Nodal Agency to procure incremental requirement of TRAS in RTM. The Commission believes that this would provide flexibility to the Nodal Agency not only to ensure additional requirement of TRAS in the system but also to take advantage of the un-requisitioned surplus available in the system closer to real time. Considering the day-ahead scheduling practice followed in India with the provision of right to recall and availability of un-requisitioned surplus in the system, the nodal agency has been given the flexibility of procuring TRAS on day-ahead basis for the next day after taking into account the likely availability of TRAS resources on real time basis. In anticipation of adequate resources likely to be available in the system, the Nodal Agency may procure only part of the TRAS requirement on day-ahead basis and procure the remaining on real-time basis through RTM.

5.5 It is envisaged that the power exchange would provide the same window available in the Day Ahead Market and the Real Time Market to submit bid for TRAS-Up or TRAS-Down. The TRAS provider shall submit the sell bid for TRAS-Up and / or TRAS-Down in Rs./MWh along with the offer volume in MW while making sure that the capacity offer in the same time-block, is separate and non-overlapping. The TRAS Provider cleared in the day ahead market can place incremental bid in real time and those not cleared in the day ahead market can also place their bids again in the Real Time Market.

5.6 The power exchange shall collect the bids for TRAS-Up and TRAS-Down and share the same with the Nodal agency for price discovery. The responsibility of price discovery has been entrusted to the Nodal Agency because Ancillary Services are to be maintained by the Nodal Agency and also centralising price discovery at the Nodal Agency level would be more efficient as availability of transmission corridor can be factored in simultaneously while running the price discovery engine. Further, in the absence of a centralised platform for price discovery, it would be difficult for the Nodal Agency to decide as to what extent of the total requirement should be procured from any specific power exchange.

5.7 It is expected that the power exchanges and the Nodal agency will create suitable infrastructure and procedures to enable effective implementation of bidding and communication system for Ancillary Service Market.

Price Discovery for TRAS

5.8 As regards pricing mechanism for Ancillary Service product, the Commission deliberated on two alternatives, viz. Uniform Market Clearing Price and Pay-as-bid price mechanism. The uniform market clearing pricing helps in discovering the true system marginal price and has already gained acceptance in the Indian Power sector. Under uniform price mechanism optimal strategy of any participant would bid at marginal cost. TRAS-Up being similar to energy market, it has been proposed that the principle of uniform market clearing price (MCP) would be followed for compensating the TRAS-Up Providers. However, in case of TRAS-Down, the Commission has proposed pay-as-bid principle on the understanding that the market size of this segment would be small and the concept of system marginal price might not be relevant in this context. The high variable-cost generating stations are likely to operate at their technical minimum and might not be in a position to offer TRAS-Down, while the low-cost generating stations would either be used for energy or for TRAS-Up. The generating stations with mid-range variable costs would be ideal candidates for TRAS-Down service. These stations would have the liberty to quote a price after duly factoring in their risks and rewards for participation in TRAS-Down.

5.9 The responsibility of discovering the MCP for TRAS-Up will lie with the Nodal Agency. The highest Energy-Up bid corresponding to the requirement for TRAS-Up in the respective day ahead and real time Ancillary Services Market shall form the Market Clearing Price. All TRAS-Up Providers cleared would be paid the MCP of the Ancillary Market in DAM or RTM, as the case may be. For TRAS-Down, the Nodal Agency shall stack all TRAS-Down bids in a descending order from the highest Energy-Down bid to the lowest Energy-Down bid and the Nodal Agency shall select the TRAS-Down Providers to meet the estimated TRAS requirement in that order.

5.10 The Commission has not proposed any price cap for the TRAS. However, if the situation so demands (for instance, to arrest the volatility in prices), the Commission may provide price cap for TRAS-Up.

Scheduling and Despatch of TRAS

5.11 The Nodal Agency shall publish information in respect of the TRAS-Up and TRAS-Down cleared for the Day Ahead Market and the Real Time Market on its website, and shall simultaneously communicate to the concerned power exchanges for onward communication to the selected TRAS providers. The schedule for TRAS shall become effective from the time block starting 15 minutes after issue of the despatch instruction by the Nodal Agency. The Nodal Agency may issue despatch instruction from any time block after the above-mentioned time block, if required, based on the anticipated system conditions. Scheduling and Despatch of the selected TRAS providers shall be in accordance with the Grid Code.

5.12 In case where the requirement of dispatch for TRAS-Up and the quantum cleared in DAM and RTM for TRAS-Up are equal, all the resources cleared in DAM and RTM shall be dispatched. The same shall apply in the case of TRAS-Down.

5.13 However, there can be situations where the requirement for despatch of TRAS may be less than the TRAS quantum procured in the market and in such a situation, the Nodal Agency shall dispatch the most economical set of resources. The TRAS-Up Providers cleared in the market (DAM/RTM) with lower MCP for TRAS- Up shall be despatched first and the remaining quantum shall be despatched from the market (DAM/RTM) with higher MCP for TRAS-Up, and the resources within a particular market shall be despatched on pro rata basis.

5.14 In case of a situation where requirement of TRAS-Down is less than procurement in the market, the Nodal Agency shall prepare a combined stack of all the TRAS-Down providers cleared in the Day Ahead Market or Real Time market for TRAS-Up and shall despatch them in the descending order of their Energy-Down bids. Accordingly, the selected TRAS-Down Provider with the highest Energy-Down bid shall be despatched first, followed by the TRAS-Down Provider with the next highest Energy-Down bid and so on. This has been illustrated in the following schematic.

Figure-4: Deployment of TRAS-Up

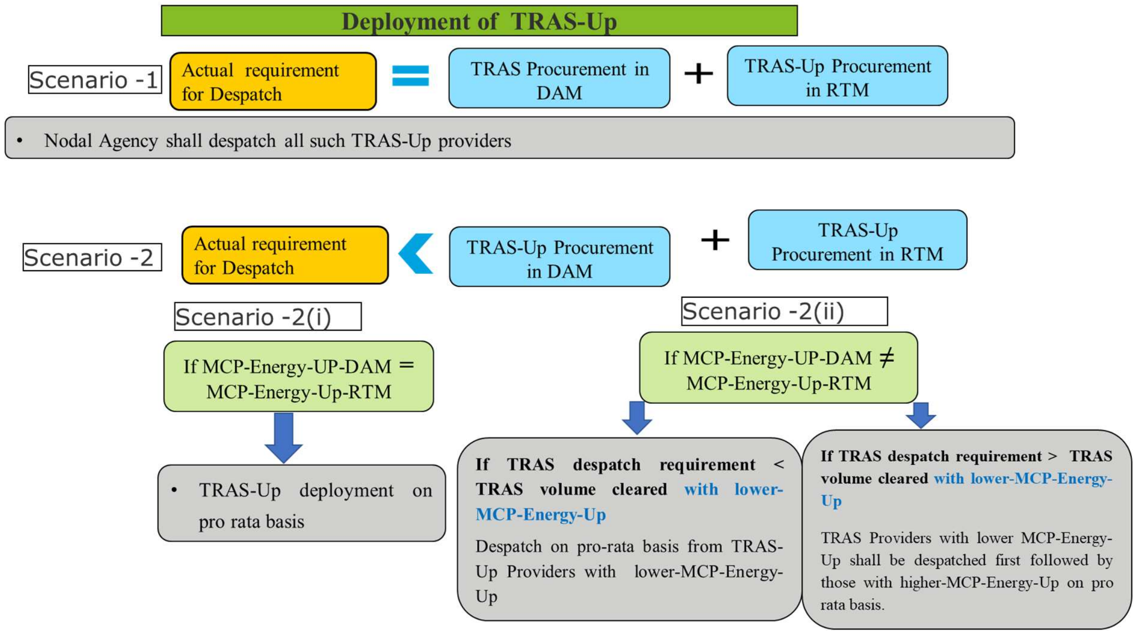
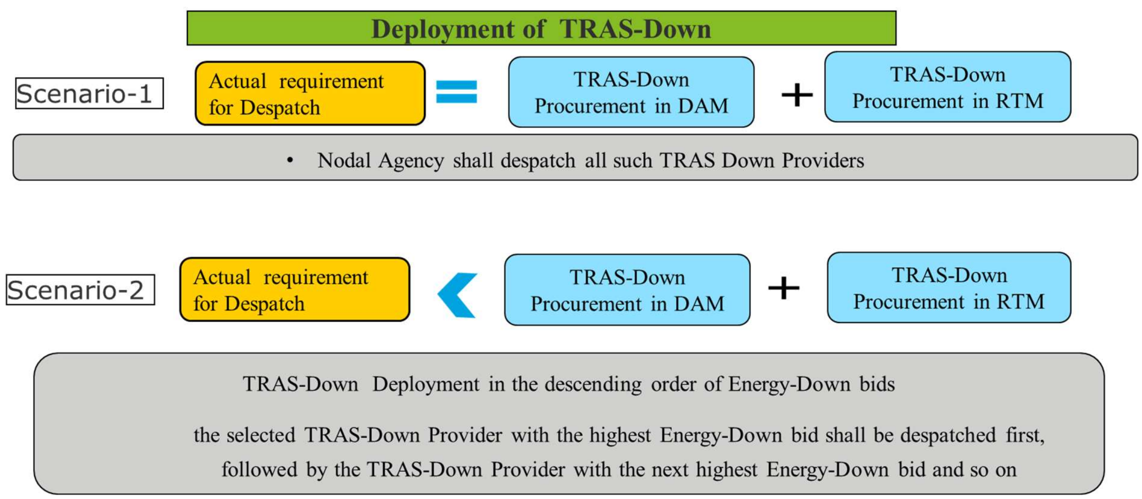


Figure-5 : Deployment of TRAS-Down



Payment for TRAS

5.15 As discussed above, TRAS-Up shall be cleared on the principle of uniform market clearing price and accordingly, TRAS-Up Provider shall be paid at the rate of MCP-Energy-Up, as discovered in the Day Ahead Market or the Real Time Market, as the case may be, for the quantum of energy instructed to be dispatched by the Nodal Agency. There could be a situation where a TRAS-Up provider is selected but not dispatched by the Nodal Agency. In such an event, such TRAS provider shall be eligible for commitment charge at the rate of 10 percent of the MCP of DAM or RTM, as the case may be, subject to a ceiling of 20 paise/kWh. In the Indian context under Availability Based Tariff (ABT) mechanism, the generators recover their fixed charge based on declaration of availability or commitment of capacity. This assurance of fixed charge is irrespective of whether their energy is scheduled or not. In the Ancillary Services segment also, the expectation would be to recover part of their fixed charge, if they commit their capacity but do not get despatched. The Commission believes that given the small size of Ancillary Services market, the expectation of commitment charge would not be high enough to recover their full fixed charge. AS market is likely to constitute approximately 2-3 % of the peak demand (reference contingency for secondary services as per the report of the Expert Group on review of the Grid Code is 4500 MW). This constitutes approx. 2.5% of the peak demand of 190 GW. Similar level of requirement is expected in the tertiary segment as well. This should ideally translate into an expectation of recovery of 2% to 3% of the fixed charge from the AS market. However, the Commission has assumed the expectation of 10% equivalent of fixed charge and further on the assumption of an average fixed charge of Rs 2/kWh for a generating station, 10% results in the ceiling of commitment charge of 20 paise/kWh.

5.16 TRAS-Down Providers shall pay to the Deviation and Ancillary Service Pool Account at the bid price quoted by them in DAM or RTM for TRAS-Down. In case of TRAS-Down, the Commission has not proposed any payment of commitment charge as such resources would have received payment as per their schedule in accordance with the extent scheduling and payment framework.

6. Shortfall in procurement of SRAS and TRAS or Emergency Conditions

6.1 Grid security is paramount and cannot be left entirely to mechanism of voluntary participation for SRAS or the market-based procurement for TRAS. Accordingly, with due regard to grid safety and security, the Commission has proposed to authorise the Nodal Agency to utilise, in case of shortfall of procurement of Ancillary Services, any un-requisitioned power available in the generating stations whose tariff is determined by the Commission under Section 62 of the Act .

6.2 These generating stations shall receive payment from Deviation and Ancillary Pool Account at their variable charge (as intimated by them for participation in SRAS), towards the SRAS-Up energy despatched in 15 minute time-block and shall pay back to the Deviation and Ancillary Pool Account at their variable charge, for the SRAS-Down energy despatched in 15 minutes time-block. However, for both SRAS-Up and SRAS-Down, these generating stations shall receive incentive for SRAS-Up and SRAS-Down Energy calculated based on 5-minutes aggregated secondary control signals in absolute terms.

6.3 For TRAS-Up, such generating stations shall be paid at the rate of their variable charge (as intimated by them for participation in SRAS) for the quantum of TRAS-Up despatched in the event of shortfall in procurement of TRAS-Up through AS Market and shall pay back at the rate of their variable charges, corresponding to the quantum of TRAS-Down despatched.

6.4 Notwithstanding the provision of treatment under shortfall, in case of emergency conditions for the reason of grid security as stipulated in the Grid Code, the Nodal Agency can instruct any generating station to provide Ancillary Service. In such conditions, such generating station shall be compensated at the rate of the energy charge as determined under Section 62 of the Act or adopted under Section 63 of the Act, as the case may be.

7. Accounting and Settlement of SRAS and TRAS

7.1 At present, the Regional Power Committee prepares accounts for Ancillary Service and DSM on weekly basis. The Commission proposes no change in the same. Accordingly, all the accounting for SRAS and TRAS shall be done by the Regional Power Committee on a weekly basis based as per the data provided by the Nodal Agency.

7.2 The deviation of AS Provider in every 15 minutes time block shall be calculated as under and settled as per the procedure of DSM Regulations:

MWh Deviation for AS Provider = (Actual MWh of AS Provider) − (Scheduled MWh of AS Provider including TRAS MWh) − (SRAS MWh of AS Provider)

7.3 All the settlement of payment liabilities in respect of Ancillary Service Provider (for either SRAS or TRAS or both) shall be done directly by the Nodal Agency on a weekly basis based on the accounts prepared by the Regional Power Committee. All payment liabilities for despatch of ancillary services shall be met through Deviation and Ancillary Pool Account maintained by the RLDCs.

7.4 As proposed in the draft Regulations, the Deviation and Ancillary Service Pool Account shall be charged for:

(a) the full cost of despatched SRAS-Up including the variable charge or the energy charge or the compensation charge, as the case may be, for every time-block on a regional basis as well as the incentive for SRAS, payable to the concerned SRAS Provider; and

(b) the full cost towards TRAS-Up including the charges for the quantum cleared and despatched and the commitment charge for the quantum cleared but not despatched.

7.5 Similarly, the Deviation and Ancillary Service Pool Account shall receive credits for:

(a) payments made by SRAS Provider for the SRAS-Down despatched; and

(b) payments made by TRAS Provider for the TRAS-Down despatched.

7.6 Any post facto revision of variable charge or compensation charge, as the case may be, shall not be permitted under this regulation. In order to manage the deficit in any of the Regional Deviation and ancillary Pool accounts, the Commission has provided for use of the surplus amount available in other Deviation and Ancillary Service Pool Account. The Nodal Agency shall specify the methodology in this regard in the Detailed Procedure.

7.7 A basic calculation for settlement of SRAS account for a time block in case of a generating station is provided below for easy reference:

Parameter	**Formula for evaluation parameter**
Five (05) minute SRAS MWh data	(a) [to be provided by Nodal Agency/RPC]
Fifteen (15) minute SRAS MWh data	(b) [to be provided by Nodal Agency/RPC
Total SRAS-Up	(A) = sum (a), where (a) > 0
Total SRAS-Down	(B) = sum (a), where (a) < 0
Total SRAS-Up and SRAS-Down	(C) = |A| + |B|
Total Net SRAS MWh ('positive' means net SRAS-Up and 'negative' means net SRAS-Down)	(D) = sum (b)
Payment for energy for SRAS ('positive' means SRAS provider would be paid and 'negative' means SRAS Provider would pay back) in Rs.	(E) = (D) x 1000 x (variable charge as intimated for participation in SRAS)
Incentive for SRAS	(C) x (1-NAC) x Incentive Rate
NAC in (%)	percentage Normative Auxiliary Energy Consumption for similar class of generating stations, as specified in the Tariff Regulations
Incentive Rate	based on the performance of SRAS
MWh deviation in 15-minute for AS	MWh Deviation for AS Provider = (Actual MWh of AS Provider) − (Scheduled MWh of AS Provider including TRAS MWh) − (SRAS MWh of AS Provider)

8. Transmission Losses and Charges for SRAS Providers and TRAS Providers

8.1 Considering that the Ancillary Service would be deployed by the Nodal Agency to manage system imbalance and grid safely, no transmission charges or transmission losses or transmission deviation charges shall be payable for SRAS and TRAS.

9. Detailed Procedure

9.1 The Nodal Agency shall prepare Detailed Procedure in line with the provisions in the draft Ancillary Services Regulations after stakeholder consultation within a period of 3 months of notification of these regulations and submit the same for information to the Commission. As referred in the draft Regulations, the Detailed Procedure shall contain the operational aspects of SRAS and TRAS including, but not limited to bi-directional communication system, metering and SCADA telemetry for monitoring and measurement of energy delivered under SRAS, details regarding declaration of technical parameters of SRAS provider, technical requirements for SRAS provider including Storage and Demand Response, manner of declaration of the variable charge and the compensation charge, methodology of sharing of real time data with SRAS provider, methodology of computation for SRAS, details regarding monitoring of actual response of SRAS providers, methodology of payment to SRAS and TRAS providers in case of deficit in the concerned Deviation and Ancillary Service Pool Account, details regarding Custom Participation Factor, performance measurement for SRAS Providers, details of information in respect of the TRAS cleared in the market, timeline for settlement of TRAS, other related and incidental matters.

10. Repeal and Saving

10.1 Save as otherwise provided in these regulations, Central Electricity Regulatory Commission (Ancillary Services Operations) Regulations, 2015 and all subsequent amendments thereof shall stand repealed from the date of commencement of these Regulations. Further, notwithstanding such repeal, anything done or any action taken or purported to have been done or taken including any procedure, minutes, reports, confirmation or declaration of any instrument executed under the repealed regulations shall be deemed to have been done or taken under the relevant provisions of these regulations.