CENTRAL ELECTRICITY REGULATORY COMMISSION
NEW DELHI

Coram:
Shri P. K. Pujari, Chairperson
Shri I. S. Jha, Member
Shri Arun Goyal, Member
Shri P. K. Singh, Member

No. RA-14026(11)/3/2019-CERC **Dated: 26thApril, 2022**

In the matter of
Central Electricity Regulatory Commission (Ancillary Services) Regulations, 2022 – Statement of Objects & Reasons (SOR) thereof.

STATEMENT OF REASONS

Introduction

(a) The Central Electricity Regulatory Commission (hereinafter referred to asthe 'CERC' or 'the Commission') initiated the process of notifying Ancillary Services Regulations,in exercise of powers conferred conferred under Section 178 read with clauses (h) and (i) of sub-section (1) of Section 79 of the Electricity Act (here in after referred to as the 'the Act' or 'the EA, 2003').On May30, 2021, the Commission issued the Draft Central Electricity Regulatory Commission (Ancillary Services) Regulations, 2020 (here in after referred to as the 'Draft Regulations') and on June 16, 2021 uploaded Explanatory Memorandum for the same wherein the reasons and analysis reliedupon for framing the Draft Regulations were explained.

(b) Comments/suggestions/objections from the stakeholders and interested persons on the Draft Regulation were sought by 30th June 2021, which was extended till 15th July, 2021 based on the request of stakeholders. In response, the Commission received submissions from fifty (50) stakeholders. The list of stakeholders is attached as **Annexure I** to this document. Subsequently, Public Hearing on the Draft Regulations was conducted on August 11, 2021 through video conferencing. The list of stakeholders who presented during the Public Hearing is attached as **Annexure II.**

(c) The Commission, complying with the provisions of the Act and the Electricity (Procedure for Previous Publication) Rules, 2005 proceeded to finalize the CERC (Ancillary Services) Regulations, 2022. The Commission considered the comments of the stakeholders on the Draft Regulations, views of the participants in the Public Hearing as well as their written submissions received during and after the Public Hearing. The Regulations have been finalized after due consideration of various issues raised. The analysis of the issues and findings of the Commission thereon are discussed in the subsequent paragraphs.

(d) On January 31, 2022, the Commission has notified the Central Electricity Regulatory Commission (Ancillary Services) Regulations, 2022 (here in after referred as ‘Ancillary Services Regulations, 2022’) keeping in view the mandate of the Act and the submissions of the stakeholders. However, the Commission will notify separately the date from which these Regulations would come into force.

(e) It may be noted that all the suggestions given by the stakeholders have been considered, and the Commission has attempted to elaborate all the suggestions as well as the Commission’s decisions on each suggestion in the Statement of Reasons.However, in case any suggestion is not specifically elaborated, it does not mean that the same has not been considered. Wherever possible, the comments and suggestions have been summarised clause-wise, along with the Commission’s analysis and ruling on the same. However, in some cases, due to overlapping of the issues/comments, two clauses have been combined in order to minimise repetition. The Commission has also made certain suo-motu consequential changes in order to ensure consistency among clauses.

(f) The main issues raised during the public consultation process, and the Commission’s analysis and decisions on the issues, which underlie the Regulations as finally notified, are given in subsequent paragraphs.

1 Definition and Interpretation

A. AGC Signal

Commission’s Proposal

1.1 In the Draft Regulations, definition of AGC signal was proposed as below:

"Automatic Generation Control" or “AGC” means a mechanism through which the generation of the SRAS Provider in a control area is automatically adjusted in response to the Secondary Control Signal;

Comments Received

1.2 **CESC** submitted that AGC is generally applicable within limits of Technical Minimum & provision of an interlock is critical to avoid operational hazards.

Analysis and Decision

1.3 The Commission is of the view that the Detailed Procedure to be prepared by the Nodal Agency would take into account all the required technical details of eligible SRAS Providers while sending AGC signal and, therefore, it has been decided to retain the definition as proposed in the Draft Regulations

B. Ancillary Service

Commission's Proposal

1.4 In the Draft Regulations, definition of Ancillary Service was proposed as below:

"Ancillary Service" or "AS" in relation to power system operation, means the service necessary to support the grid operation in maintaining power quality, reliability and security of the grid and includes Primary Reserve Ancillary Service, Secondary Reserve Ancillary Service, Tertiary Reserve Ancillary Service, active power support for load following, reactive power support, black start and such other services as defined in the Grid Code;

Comments Received

1.5 **AEEE**proposedthat 'resiliency' be factored into the definition of Ancillary Service

1.6 **Mr. Sangeet Dave** commented that the term 'load following' needs to be differentiated from SRAS/TRAS and has not been used anywhere in the regulation.

1.7 **IEX** commented that definition of the Ancillary Service Market may be included to bring clarity in the scope of this Market.

1.8 **NHPC, BYPL and US-ISPF** proposed to incorporate mechanism of procurement for Ancillary Services such as active power support for load following, reactive power support, black start service etc.

Analysis and Decision

1.9 The Commission has noted the suggestion and is of the view that the definition of Ancillary Service is adequate and, therefore, it has been decided to retain the definition as proposed in the Draft Regulations.

1.10 As regards the suggestion of separate definition of Ancillary Service Market, the Commission observes that it has already been elaborated in the provision relating to Procurement of TRAS and hence there is no need to include the same in the definition.

1.11 As regards consideration of procurement mechanism for other Ancillary Services, Regulation 5 (3) provides that the mechanism of procurement, deployment for remaining Ancillary Services would be specified in the Grid Code or under this regulation separately by the Commission.

C. Compensation Charge

Commission's Proposal

1.12 In the Draft Regulations, Compensation Charge wasdefined as below:

"Compensation charge" means the price declared by an SRAS Provider other than a generating station for participation in SRAS;

Comments Received

1.13 **BYPL** sought clarification about the mechanism to judge reasonableness of these compensation charges quoted by the SRAS providers.

1.14 **POSOCO** sought clarification on determination of compensation charge along with provision for capping the same. POSOCO also sought modification in the definition to include generating station such as State hydro generating station or renewable generating station which may wish to participate as SRAS Provider but does not have two-part tariff.

Analysis and Decision

1.15 The Commission noted the suggestion and modified the definition of compensation charge to bring more clarity as follows:

"Compensation charge" means the price declared by an SRAS Provider other than a generating station whose tariff is determined under Section 62 of the Act for participation in SRAS;

1.16 The "Compensation charge" is applicable for the SRAS providers other than the generating stations whose tariff is determined under section 62 of the Act, and such entities shall be free to declare compensation charge as they deem fit. The custom participation factor is expected to ensure that the efficient and cost effective SRAS providers are dispatched. As regards the manner of declaration of the compensation charges, the same would be covered in the Detailed Procedure to be issued by the Nodal Agency as specified in the Regulation 23.

D. <u>Demand Response</u>

1.17 In the Draft Regulations, Demand Responsewasdefined as below:

"Demand Response" means variation in electricity consumption by end consumers or drawal by a control area, as per system requirement identified by the Nodal Agency;

CommentsReceived

1.18 **CER – IIT Kanpur** proposed that variation in drawal by the control area should be attributable to demand response only if this is achieved through back-to-back volunteer demand reduction by the consumers, rather than load management/load shedding by the distribution company. It was also requested that 'demand response aggregator' should also be defined, and its role be specified in the definition of demand response for clarity.

1.19 **BYPL and USISPF** commented that in order to bring more clarity, role of distribution company (discom) in providing demand response may be stipulated in the Detailed Procedure or in the Grid Code.

1.20 **Shri Sangeet Dave** proposed that 'Demand Response' requires to be defined in terms of MW/min for different regions and should be part of regulation. Provisions of failure to meet demand response and information with load-frequency characteristics of region may also be specified in the Regulation.

1.21 **AEEE** suggested to expand the 'Demand Response' with 'Demand Flexibility' as the ability of the demand side to vary in accordance with the grid requirement across different timescales during uncertainty. AEEE also suggested to add separate definition of Aggregator as an entity that aggregates one or more demand-side resources or energy storage resources for purposes of participation in Ancillary Service Market.

Analysis and Decision

1.22 The Commission noted the suggestion and modified the definition of Demand Response as follows:

"Demand Response" means variation in electricity consumption by end consumers or drawal by a control area, on standalone or aggregated basis, as per the system requirement identified by the Nodal Agency;

1.23 As regards thethe modalities for participation of Demand Response as ancillary service providers, the same would be stipulated in the Detailed Procedure by the Nodal Agency.

E. <u>Energy Storage</u>

1.24 In the Draft Regulations, definition of Energy Storagewas proposed as below:

"Energy Storage" in relation to the electricity system, means a facility where electrical energy is converted into any form of energy which can be stored, and subsequently reconverted into electrical energy;

Comments Received

1.25 **CER – IIT Kanpur** proposed that definition of energy storage may be modified by adding the text '*which is injected back to the grid*' at the end to bring clarity.

1.26 **AEEE** suggested to redefine the definition to include Electric Vehicles (EV) and EV charging station.

Analysis and Decision

1.27 The Commission is of the view that the definition is adequate and therefore, it has been decided to retain the definition as proposed in the draft Regulation.

1.28 As regards the suggestion to include EV and EV charging station, the Commission is of the view that the modalities of participation of EV and other such technologies as Ancillary Service Providers would be detailed out in the Detailed Procedure by the Nodal Agency.

F. <u>Nodal Agency</u>

1.29 In the Draft Regulations, Nodal Agency wasdefined as below:

"Nodal Agency" means the National Load Despatch Centre which shall be responsible for implementation of the Ancillary Services at the inter-State level through the Regional Load Despatch Centres;

Comments Received

1.30 **PCKL** suggested to modify the definition to include intra-State level implementation through State Lod Despatch Centres.

1.31 **POSOCO** proposed that definition may be modified as follows:

”Nodal Agency" means the National Load Despatch Centre which shall be responsible for implementation of the Ancillary Services at the inter-State level through the Regional Load Despatch Centres <u>and in coordination with State Load Despatch Centres</u>;

1.32 **Shri Sangeet Dave** suggested that instead of Nodal Agency, NLDC may be used to avoid jargon.

Analysis and Decision

1.33 The Commission is of the view that reserves need to be maintained and shared by all control areas in the interest of grid security. Through these Regulations, the Commission has taken initiatives to provide regulatory framework at regional level, which comes under the jurisdiction of the Commission. It is believed that complimentary framework at State Control Area would be implemented by the State Electricity Regulatory Commission to ensure that the responsibility of maintaining reserves is shared by entities at regional level as well asstate level.

1.34 As regards POSOCO’s suggestion, the required coordination with the State Load Despatch Centres through RLDCs is inherent for system operation and has been elaborated in the Grid Code. Therefore, the Commission has decided to retain the definition of Nodal Agency as proposed in the Draft Regulations.

G. <u>Un -Requisitioned Surplus (URS)</u>

1.35 In the Draft Regulations, URS has been defined as below:

“Un-Requisitioned Surplus” or “URS” means the capacity in a generating station that has not been requisitioned and is available for despatch, and is computed as the difference between the declared capacity of the generating station and its total schedule;

CommentsReceived

1.36 **Shri Sangeet Dave**suggested to modify the definition to stipulate that URS is a positive difference between DC and Schedule of a generating station.

1.37 **CER IIT** suggested that URS be calculated prior to scheduling and dispatch of respective ancillary services.

1.38 **BYPL and US-ISPF** requested that identification of generating stations for providing ancillary services on day ahead basis or in real time should be based on confirmations of Discoms/Beneficiaries for not scheduling certain URS Capacity.

1.39 **POSOCO** requested to rename the URS as Unscheduled Surplus (USS) to differentiate it from temporary reallocation of URS. POSOCO also highlighted that the declaration of capacity (DC) is followed by generating stations under Section 62 or 63and merchantplants or Captive Power Plants don't declare DC. Hence, there is need for On-bar or off-bar DC for reserves assessment.

Analysis and Decision

1.40 The Commission noted the suggestions and is of the view that no change is required in the definition of URS. The Detailed Procedure to be prepared by the Nodal Agency may incorporate appropriate provision to ensure on bar/off bar capacity in respect of the AS providers while taking into consideration the existing scheduling practices.

2 Scope of Regulations

2.1 The Scope of these Regulations as per Regulation 4 was proposed as under:

"These regulations shall be applicable to regional entities, including entities having energy storage resources and demand side resources qualified to provide Ancillary Services and other entities as provided in these regulations."

Comments Received

2.2 **CESC** sought clarification as to which entities can be deemed as "demand side resources" and also whether state entities or entities embedded within a state can also participate as an Ancillary Service (AS) Provider.

2.3 **Power Grid** requested to clarify the requirement of access i.e. STOA/MTOA/LTA for transactions under ancillary services in the regulations.

2.4 **SRPC** suggested to remove 'other entities' from the Scope.

2.5 **Statekraft** proposed that the regulation may explicitly mention the type of storage devices such as pumped hydro, battery storage systems etc for better clarity on eligible participants.

2.6 **NTPC** submitted that the existing generators should be encouraged to set up storage facilities within their premises, including utilisation of the existing transmission infrastructure etc and should be allowed to provide Ancillary Services. NTPC further commented that a suitable mechanism needs to be developed for participation of Discoms to provide Demand Side Resources while considering their Universal Service Obligation.

2.7 **US-ISPF** suggested that the scope could be enlarged to have participation of State generating stations and private sector generating stations operating in the State.

2.8 **Indi Grid Trust** suggested that the definition of Entity or Regional Entity may also be provided in Regulations. Indi Grid Trust also suggested that the existing transmission licensees [projects under tariff based competitive bidding (TBCB) as well as regulated tariff mechanism] be allowed to participate with storage as a separate entity or as part of their other business.

Analysis and Decision

2.9 As regards the suggestion regarding clarity on Storage and Demand side Resources, the Commission believes that the Detailed Procedure to be prepared by the Nodal Agency may incorporate appropriate provision in this regard after due consultation with various stakeholders. The issue of access andtreatment of storage owned bytransmission licensee is outside the purview of the AS Regulations and will be governed by the relevant regulations of the Commission.

2.10 The Commission has noted the suggestions and is of the view that no change is required in the scope as proposed in the Draft Regulations.

3 <u>Type of Ancillary Services</u>

Commission's Proposal

3.1 In the draft Regulations, the types of Ancillary Services wereproposed as under:

(1) *There shall be 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*
(2) *The mechanism of procurement, deployment and payment of SRAS and TRAS as referred to in sub-clauses (b) and (c) of clause (1) of this Regulation shall be as specified in these regulations.*
(3) *The mechanism of procurement, deployment and payment of Ancillary Services, referred to in sub-clauses (a) and (d) of clause (1) of this Regulation, shall be as specified in the Grid Code or under these regulations to be specified separately, as the case may be.*

Comments received

3.2 **POSOCO** highlighted that in addition to frequency control ancillary services, framework for other forms of ancillary services such as voltage control and black-startalso need to be established. POSOCO also suggested relevant amendments in the Grid Code in this regard while pointing out the submission of the report on Reactive Power Management and Voltage Control Ancillary Services (VCAS) in India to the Commission.

3.3 **Statekraft** suggested that a consolidated Regulation may be notified to avoid any complexities of multiple regulations.

3.4 **NHPC, APMuL, IESA, AES, IRADe, Statekraft, CESL and Renew Power** suggested to provide regulatory mechanism in respect of PRAS. **Greenko** suggested to include market-based procurement of PRAS in the Regulations for promotion of Battery Storage Technologies.

3.5 **CESL and IWPA** suggested to include role of ancillary services in applications such as voltage maintenance and reactive power management.

3.6 **Fluence, AES, IESA, IRADe, US-ISPF, Statekraft** suggested the need for faster responding reserves like Battery Energy Storage System (BESS) and Demand Resources

(DRs) for effective integration of RE sources. According to them, this could offer a significant market opportunity for energy storage in the immediate future if a technology neutral market design allows it to compete with traditional assets.

3.7 **BYPL, Tata Power, Fluence** sought clarity on differentiation between the primary and the secondary response.

3.8 **Tesla** suggested that a long-term, tailored market framework to support reliability and system security will necessarily rely on the capabilities of fast-response and flexible resources, including demand side response, battery storage and distributed energy resource participation.

Analysis and Decision

3.9 Many Stakeholders appreciated the introduction of Secondary Reserve Ancillary Service (SRAS) and shifting of Tertiary Ancillary Reserve Services (TRAS) from administrative mechanism to market mechanism. Some stakeholders suggested to provide regulatory framework for Primary Reserve Ancillary Services (PRAS) while others also suggested market-based mechanism for PRAS.

3.10 The Commission noted the suggestions of the stakeholders and would like to highlight that 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. The Commission is of the view that before providing any alternative procurement frameworka comprehensive study and its implications need to be assessed. Accordingly, the Commission has retained the provision that the procurement, deployment and payment mechanism for SRAS and TRAS shall be as specified in these regulations. Further, the Commission has also kept an enabling provision to provide for procurement, deployment and payment mechanism for PRAS and other types of Ancillary Services, by amending these Regulations based on the requirement and market reality.

3.11 As regards the suggestion of POSOCO to make suitable amendment in the Grid Code for Voltage Control and Reactive Power Management, the Commission is of the view that itis outside the purview of the proposed Regulations and may be considered while reviewing the existing Grid Code by the Commission.

4 Regulation 6: Estimation of Reserves by the Nodal Agency

Commission's Proposal

4.1 The provision regarding Estimation of Reserves by the Nodal Agency was proposed in the Draft Regulationsas follows:

"6. Estimation of Reserves by the Nodal Agency

(1) *The Nodal Agency shall, in coordination with RLDCs and SLDCs, estimate the quantum of requirement of SRAS and TRAS for such period and based on such methodology*

as specified in the Grid Code.

(2) *The Nodal Agency shall re-assess the quantum of requirement of SRAS and TRAS on day-ahead basis and incremental requirement, if any, on real time basis.*

(3) *The requirement of SRAS shall be estimated on regional basis."*

Comments Received

Estimation Methodology

4.2 **POSOCO** suggested that the Commission may direct the Nodal Agency, in coordination with RLDCs and SLDCs, to estimate the quantum of requirement of SRAS and TRAS for such period and based on such methodology as specified in the draft IEGC recommended by the Expert Group.

4.3 **POSOCO** also proposed that each state control area may also give block-wise reserves quantum in addition to block wise daily forecast of demand as per Regulation 5.3 of the IEGC. According to POSOCO, this provision is important for enforcement and compliance, as robust forecasting would be key for activation and deployment of reserves by the system operators.

4.4 **Shri P.K Aggarwal** in his comments suggested a performance criterion of nodal agency based on the error in actual quantum used and estimated quantum of TRAS reserve by the nodal agency.

Estimation on day ahead and real time basis

4.5 **NTPC** suggested that themethodology for estimation of reserve need be designed carefully by taking into account the limited opportunity of participation by the central generating stations on day ahead basis and also requested that the cost of procurement and deployment should be published transparently on daily and monthly basis.

4.6 **SRPC** suggested that reserve requirement may be estimated as per the methodology specified in the Grid Code or in the Detailed Procedure by the Nodal Agency, as the case may be.

4.7 **CESC, Greenko and Statekraft** suggested that reserves requirement as assessed by the Nodal Agency may be made public upfront, so that AS provider can plan and cater its resource efficiently.

4.8 **Renew Power**and **RPG**suggested that requirement of AS should be made in advance by the Nodal Agency to allow service providers to plan and deploy optimal and efficient capacities.

4.9 **IRADe** commented that the method for estimating the quantum of all types of ancillary services (i.e. Primary, Secondary, Tertiary) should be approved by CEA/CERC to ensure checks and balances.

4.10 **CSTP** commented that estimation of the quantum of requirement of SRAS and TRAS should also consider the RE generation plans and EV demand penetration plans for the future. Ultimately, the grid flexibility should be assessed on the basis of future estimated ramping rate requirements.

4.11 **Enel Green** stated that DAM and RTM for energy and Ancillary Service shall operate independently and hence proposed modification in Regulation (6) (2) as under:

"The Nodal Agency shall re-assess the quantum of requirement of SRAS and TRAS on day-ahead basis and incremental requirement, if any, on real time basis and shall bid for such quantum on market platforms specifically developed for determining the market clearing price of Ancillary Services."

4.12 **Torrent Power Ltd** suggested that Ancillary Service mechanism is primarily for safety and security of the grid "on real time basis", so projections of SRAS / TRAS requirement on day ahead basis needs to be clarified.

<u>Estimation of SRAS on Regional basis</u>

4.13 **Shri Bhanu Bhushan** submitted that a clear demarcation of control areas is most important in a large inter-connection like the integrated grid of India. He questioned centralisation of control at NLDC while considering each region as a control area for SRAS. He advocated decentralised generation control by defining each State as one control area.

4.14 According to **AEEE**, RLDC and SLDC would have better visibility to ensure locational value to grid support. **AEEE** emphasized the role of RLDCs and suggested both centralised and decentralised procurement of ancillary services.

4.15 According to the **POSOCO**, the responsibility to provide reserve response should be shared by all control areas in a distributed manner in the interest of grid security and in a participative manner so that there is no tendency to pass on the responsibility to other entities.

4.16 **POSOCO** highlighted the need for mandating Security Constrained Unit Commitment (SCUC) on day ahead basis for the creation of reserves as also recommended by the Expert Group on IEGC.

4.17 **POSOCO** while emphasizing on the need for Resource Adequacy highlighted that the determination of resource adequacy guidelines for each region is important including LoLP (Loss of Load Probability), VoLL (Value of Lost Load) and Optimal Reserve Margin.

4.18 **POSOCO** also requested for simultaneous notification of the revised IEGC along with Ancillary Services Regulations or to take care of the transition, it suggested that suitable provision be made in the AS Regulations for necessary details regarding implementation of AS framework in the Detailed Procedure to be stipulated by the Nodal Agency.

Analysis and Decision

4.19 Some stakeholders suggested to detail out the methodology of estimation of reserves in the AS Regulations. Others suggested that the estimation should be known to all participants in advance. Some stakeholders emphasised upon decentralised control of reserves by defining each State as acontrol area.

4.20 The Commission has noted the suggestion and accepted the view of the stakeholders regarding publishing the required quantum of SRAS and TRAS on the website of the Nodal Agency to ensure transparency. The Commission also agrees with the view that reserves need to be maintained at both regional and state control areas to make sure that responsibility of providing reserves is shared by all control areas. However, with due regard to its jurisdiction under the Act, the Commission has framed the Regulations for Ancillary Service at inter-State level and the Commission believes that complementary framework would be implemented by the State Electricity Regulatory Commissionsfor respective State Control Areas. The Commission would also like to emphasise that coordination among load despatch centres is paramount for ensuring grid security. Accordingly, Regulation 6(1) has been modified appropriately to emphasize the coordination among NLDC, RLDC and SLDCsand also to provide that the quantum of SRAS and TRAS at regional level shall be estimated after taking into accountreserves to be maintained by each state control area.

4.21 As regards the suggestions of detailing out the methodology of estimation of reserves, the Commission has decided that until specific provisions are made in this regard in the Grid Code, the Nodal Agency shall propose interim methodology for estimation of adequate reserves within two months from the date of notification of these regulations for approval of the Commission.

4.22 As regards the apprehension regarding centralised control of ancillary service, the Commission would like to clarify that the Ancillary Service framework at inter-state level shall be implemented by NLDC through RLDCs. Involvement of RLDCs has not been ignored in any manner. As updated by the NLDC in their feedback report on AGC pilot, submitted before the Commission in January 2021, presently secondary control with each of the five regional grids in India has been embedded along with required SCADA and Energy Management System at NLDC and NLDC proposes to shift the AGC infrastructure to the RLDCs in the next SCADA/EMS upgrades at RLDCs. Hence, until the required AGC software is placed at all RLDCs, the SRAS can be implemented by Nodal Agency.Suitable provision has been made to this effect in the final Ancillary Service Regulations, 2022.

4.23 As regards the suggestion of SCUC and Resource Adequacy, the Commission is of the view that it is outside the purview of the AS Regulations and shall be considered by the Commission while reviewing the existing Grid Code.

<u>Part 1: Secondary Reserve Ancillary Service (SRAS)</u>

5 <u>Regulation 7: Eligibility for an SRAS Provider</u>

Commission's Proposal

5.1 The eligibility criteria for SRAS providers was proposed in the Draft Regulations as under:

"**7.** ***<u>Eligibility for an SRAS Provider</u>***

(1) *A generating station or an entity having energy storage resource or demand side*

resource, connected to inter-State transmission system or intra-State transmission system, shall be eligible to provide Secondary Reserve Ancillary Service, as an SRAS Provider, if it

(a) *has bi-directional communication system with NLDC or RLDC, as per the requirements stipulated in the Detailed Procedure by the Nodal Agency;*

(b) *is AGC-enabled, in case of a generating station;*

(c) *can provide minimum response of 1 MW;*

(d) *has metering and SCADA telemetry in place for monitoring and measurement of energy delivered under SRAS, as stipulated in the Detailed Procedure by the Nodal Agency;*

(e) *is 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*

Comments Received

5.2 **Shri Arun Kumar** (IIT Roorkee) welcomed the inclusion of energy storage and demand response resources as eligible resources for providing Secondary Reserve Ancillary Service (SRAS) and Tertiary Reserve Ancillary Service (TRAS) claiming that the growth of energy storage and Distributed Energy Resources (DERs) will be encouraged by these regulations.

5.3 C**ER IIT Kanpur and POSOCO** suggested phase wise implementation of SRAS/TRAS for regional entities and intrastate entities. **POSOCO** suggested that all the SRAS and TRAS providers may be mandated to compulsorily register with respective RLDC in addition to SLDC. **Tesla** sought clarity on the process for registration of storage assets.

5.4 **Shri Bhanu Bhushan** and **CESC** sought clarity regarding modalities of measurement as well as monitoring of performance of intra-state entity as SRAS provider.

5.5 **MSEDCL, WBSEDCL and PCKL** suggested that intra-State generators should be allowed only if DISCOM has given consent to the concerned generator(s) in order to avoid any commercial dispute.

5.6 **PCKL** commented that it would be difficult for the generating stations connected to intra-State transmission system to provide SRAS/TRAS, as intra State ABT, Scheduling and Accounting framework have not been implemented in majority of the States.

5.7 **POSOCO** sought clarification as to whether a Discom can be considered as a demand side resource and whether demand side resource and storage resource as entity must be standalone or could it be a portfolio to participate as SRAS provider. It was also requested to clarify whether EV aggregator would also qualify as a demand side resource.

5.8 **Tata Power** suggested that intra-State gas-based generators should be made eligible to participate in SRAS and TRAS because of their superior ramping capability.

5.9 **Radiance Renewable Pvt Ltd. (RRPL)** suggested that regulations should provide specific provisions for renewable energy sources so as to encourage participation of renewable energy sources in providing ancillary services.

5.10 **ERPC** submitted that in the existing scenario, RRAS mechanism is in place for all Central Sector ISGS including one IPP (MPL) in the Eastern Region. However, AGC is enabled in only one ISGS (Barh STPS of NTPC).

5.11 **Shri Arun Kumar**sought clarification on whether energy storage and demand-side resources are required to be AGC-enabled to provide SRAS and the mechanism through which these resources will receive the SRAS signals.

5.12 **Greenko** suggested that since secondary control involves automatic control signals, all the entities should be equipped with devices which can respond to such signals automatically.

5.13 **POSOCO** suggested that the energy storage systems also need to be AGC-enabled in order to receive and respond to AGC signals.

5.14 **POSOCO** commented that there is a need for separate function and responsibility mandated by the Ancillary Services regulatory framework for the Communication Providers (CTUIL, PGCIL etc.) in case of SRAS.

5.15 **POSOCO** suggested to introduce Communication Providers (CTU, PGCIL etc.) to provide end to end redundant communication system between the SRAS Provider and the Nodal Agency ensuring route diversity and dual communication.

5.16 **SRPC** highlighted that the regional entities mostly have direct communication link with RLDC and with NLDC.In that scenario, the automatic secondary control signal to generators/demand side resources should be sent via existing communication system between regional entities and RLDCs.

5.17 **AES** India requested to relook into the response time defined vide draft regulation for SRAS to effectively include fast response resources like BESS.

5.18 **CESC and Dhariwal Infra** suggested that thewordings“providingthe entireSRAScapacity obligation within 15 minutes”may be changed to “reachingthetargetloadgenerationwithin15minutes”.

5.19 **Shri Asit Singh** submitted that at regional level the minimum quantum for SRAS Provider to offer should be 10 MW considering the telemetry, metering errors, SCADA errors etc. and to have tangible benefit at regional level.

5.20 **Wartsila** commented that the duration between receiving an SRAS signal and response time by the service provider to fulfil its obligation should be shorter. SRAS is usually a contingency response and the regulation should require the service provider to fulfil the entire obligation within 5 minutes from receiving the signal.

5.21 **Wartsila** alsosuggested that minimum response by an entity/generating station should be a function of the voltage at which it is connected to the grid and preferably at-least 10-15% of their capacity/capability to avoid non-serious players.

5.22 **Tesla**suggested to remove the requirement of sustained capability of 30minutes for secondary services as these would be a deterrent for storage.

5.23 Some stakeholders (**Sangeet Dave, IRADe**) sought clarity on the expected response from SRAS providers intra-15 minutes. Some stakeholders (**Fluence, Sangeet Dave, IRADe, Wartsila, US-ISPF, NTPC, Tesla-Motor India**) also suggested that NLDC should upfront determine the desired ramp response rates in MW/min or MW/second for all participating entities in SRAS/TRAS.

5.24 **Power Grid** sought regulatory provisions for new entities, which are not connected to ISTS but want to provide SRAS and TRAS. The requirement of minimum quantum of 50 MW and for applying connectivity to the Grid as per CERC Connectivity Regulations, 2009 may be relaxed.

5.25 **PCKL** commented that during the event of responding to SRAS signal, sign change should be exempted during such time for such entity.

5.26 **MP Ensytems** recommended for creating a sandbox environment to assess the feasibility of the demand-side resources participating in such mechanisms.

5.27 **Abutus Consultant** commented that regulation should address dynamic pricing options such as time of use (TOU), critical peak pricing (CPP), critical peak rebate (CPR), real time pricing (RTP) and variable peak pricing (VPP) that reflect time-varying cost of electricity supply, and have been in use worldwide to encourage peak load management and demand reduction.

5.28 **IESA** recommended to procure at least 25% of SRAS capacity (e.g. 1000 MW of FRAS out of 4000MW of Secondary Response Ancillary Service) through POSOCO in a competitive bidding with a term of at least 3- 5 years.

5.29 Some stakeholders suggested to include RE with or without storage, Virtual Power Plant also to be included in eligibility for SRAS. (**Sangeet Dave, IWPA, CSTP, Ekniti, MP Ensystems, RRPL, CER-IIT Kanpur**).

5.30 Some Stakeholders like **CER IIT, MP Ensytems, CSTEP** etc. emphasized the need of aggregator for emerging technologies like Energy Storage, Demand Side Resources and EV etc.

5.31 Some Stakeholders like **Arbutus Consultant, Shri Sangeet Dave, CESC** etc. requested to provide detailed technical and operations infrastructurerequirementfor becoming eligible as SRAS Providers.

5.32 Some stakeholders such as **IRADe, US-ISPF, TESLA, IESA** etc. suggested to incentivize the resources responding intra-15 minute-period such as pumped storage hydro power plant, electrochemical batteries and demand response.

Analysis and Decision

5.33 Some Stakeholders sought clarification on modalities of accounting and performance evaluation of emerging technologies such as energy storage system (ESS) and demand side resources (DR) for participation as SRAS Providers. Others also requested to specify therequirement of hardware, software, network communication and other critical infrastructure for AGC enablement. Given the emerging nature of the technologies such as ESS, DR and EV, the Commission is of the view that details in these regards be stipulated by the Nodal Agency in the Detailed Procedure after stakeholder consultation.

5.34 Several countries have allowed energy storage and demand side resources to provide secondary and primary reserves, recognizing their ability to follow control signals more accurately and much faster than other technologies. However, 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. The Commission believes that these Regulations would facilitate participation of the entity having energy storage resource or an entity capable of providing demand response on its own or through an aggregator. As regards the participation of renewable energy generators, EV or Discom to provide SRAS, the Commission is of the view that as long as such entities fulfill the eligibility criteria there should not be any entry barrier for them to participate as SRAS Providers. The required checks and balances can be built in the Detailed Procedure. Accordingly, the Commission has decided that the Nodal Agency shall prepare the required technical and operational criteria for enabling such entity to participate as Ancillary Service Providers.

5.35 The Commission has noted the suggestions of the stakeholders regarding the need of communication system and the proviso to Clause (a) of Regulation 7 (1) has been appropriately modified.

5.36 Regarding AGC enablement of SRASProviders other than a generating station, the Commission is of the view that the Detailed Procedure should ensure that all such entities are equipped with devices which can respond to secondary control signals to provide SRAS.

5.37 On the issue of minimum response of 1 MW from SRAS, the Commission is of the view that this will facilitate larger participation and would create opportunities for emerging technologies such as ESS and DR. The concern regarding participation by non-serious players can be handled with other technical and operational modalities. Hence, the Commission has retained the provision of minimum response as proposed in the Draft Regulations.

5.38 The provision regarding capabilities of SRAS Providers to respond within 30 seconds and providing entire capacity within 15 minutes, has been proposed in line with the frequency continuum envisaged by the Commission for Primary, Secondary and Tertiary Ancillary Services in India in its earlier Orders for providing roadmap to operationalise reserves in the county and the existing metering and scheduling system of 15 minutes time block. The modalities of operation would be covered in the Detailed Procedure by the Nodal Agency.

5.39 The Commission welcomes the suggestion of procuring some portion of SRAS in advance with longer duration contracts, but is of the view that such a stipulation needs to go through public consultation before it is finalised. The Commission may consider such a proposition separately based on review of implementation of SRAS framework as provided in the Ancillary Service Regulations 2022.

5.40 Based on the above, Regulation 7 has been modified appropriately.

6 <u>Activation and Deployment of SRAS</u>

Commission's Proposal

6.1 Activation and Deployment of SRAS was proposedin the Draft Regulations as under*:*

" 8. *Activation and Deployment of SRAS*

(1) *SRAS shall be activated and deployed by the Nodal Agency on account of the following events to maintain or restore grid frequency within the allowable band as specified in the Grid Code and replenish primary reserves:*

(a) Area Control Error (ACE) of the region deviating from zero (0) and going beyond the minimum threshold limit of ±10 MW;

(b) Such other events as specified in the Grid Code.

(2) *The Area Control Error (ACE) for each region would be auto-calculated at the control centre of the Nodal Agency based on telemetered values, and the external inputs referred to in clauses (3) and (4) of this regulation, as per the following formula:*

*ACE = (Ia - Is) - 10 * Bf * (Fa - Fs) + Offset*

Where,

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

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

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

Fa = Actual system frequency in Hz

Fs = Schedule system frequency in Hz

Offset = Provision for compensating for metering error

(3) Frequency Bias Coefficient (Bf) shall normally be based on median Frequency Response Characteristic during previous financial year of each region and refined from time to time.

(4) Offset shall be used to account for metering errors and shall be decided by the Nodal Agency for the respective region.

(5) Nodal Agency may operate SRAS in any of the three control modes viz., tie-line bias, flat frequency or flat tie-line depending on grid requirements."

Comments Received

6.2 **POSOCO** suggested that Frequency Bias Coefficient shall be assessed and declared by the Nodal Agency as per Detailed Procedure. **POSOCO** also requested to define three operating modes viz., tie-line bias, flat frequency or flat tie-line depending on the grid requirements for better clarityin the regulation.

6.3 **POSOCO** commented that the expression “deviating from zero”in draft Regulation 8(1)(a) is superfluous and may be deleted.

6.4 **BYPL** submitted that the events to trigger SRAS should be clearly specified in the Grid Code and there should be a system of regulatory oversight for verification of occurrences of such events.

6.5 **NTPC and PCKL** commented that considering the capacity handled in the National Grid, the minimum threshold limit of ±10 MW appears to be too low; the same should be reassessed.

6.6 **SRPC** suggested that Nodal Agency may specify the methodology/data to be considered for calculating ACE in the Detailed Procedure. SRPC also sought clarification regarding auto-calculation of ACE at every 4 second. SRPC proposed that estimation criteria for offset may be provided in the Detailed Procedure

6.7 **POSOCO** suggested to replace ‘meter error’ by the term ‘measurement error’ which would broaden the scope of different types of errors at different points.

6.8 **NHPC** commented that during high inflow season, SRAS-Down signal may not be issued to Hydro power plants.

6.9 **MP Ensytems** commented that while the detailed procedures would define the requirements, it would be useful for the regulations to clearly state the protocols to be followed during the deployment.

6.10 Some Stakeholders sought more clarity on the formula of ACE, possibly by including the definition of the term frequency bias, actual net inter change and scheduled net inter change. (**Dhariwal Infra, CESC, RPG**)

6.11 **Some stakeholders** sought clarification as to whether SRAS will become active immediately on ACE deviating beyond 10 MW or on deviation persisting beyond a certain time threshold. (**IIT Roorki, SRPC, Wartsila ,Dhariwal Infra Ltd**.*)*

6.12 Some stakeholders sought clarification on assessment of Frequency Bias Coefficient (Bf) (FRC) (**Shri Asit Singh, Dhariwal Infra, CESC, RPG**).

Analysis and Decision

6.13 According to some stakeholders the dead band of ±10 MW for ACE at regional level is very narrow and the same should be reassessed. The Commission would like to clarify that secondary reserves are deployed primarily to correct the Area Control Error (ACE). The dead band of ±10 MW proposed in the Draft Regulations is as per the recommendation by the Expert Committee on the review of the Grid Code. Area Control Error (ACE) of the region needs to be close to zero for effective frequency control. Hence, the Commission has decided to retain the dead band of ±10 MW as proposed in the Draft Regulations. However, as per the suggestions of the system operator, to bring further clarity for triggering the SRAS, the Commission has decided to remove the expression “deviating from zero (0)” from the clause

(a) of Regulation 8 (1). As regards other events of triggering SRAS, the Commission is of the view that the same would be elaborated in the Grid Code as and when the Commission reviews the Grid Code. SRAS will become active immediately as ACE of a region deviates beyond ±10 MW to *inter alia* restore the grid frequency within allowable band as specified in the Grid Code. Further, in case of any contingency, PRAS will kick in immediately to arrest the frequency change and maintain it till it is replaced by secondary response. Thus, SRAS may be deployed either to correct ACE under non-contingency conditions or to replenish PRAS under contingency condition. Accordingly, Regulation 8 (1) has been modified to provide for both these conditions.

6.14 As regards the comment seeking clarity on the definition of ACE, the Commission would like to clarify that this is a standard definition used in the power system operation across countries. Further, the Detailed Procedure should elaborate the method of assessment of Frequency Bias Coefficient (B_f) and estimation criteria of offset on account of measurement errors with illustrative examples to understand the movement and sign of power flow (inputs/export) for maintaining the safety, stability and reliability of the grid.

6.15 Based on the above, Regulation 8 has been modified appropriately.

7 Procurement of SRAS

Commission's Proposal

7.1 The provision relating to procurement of SRAS was proposed as under as Regulation 9 of the Draft Regulations:

"9. ***Procurement of SRAS***

(1) *SRAS shall be procured on regional basis by the Nodal Agency through the mechanism as specified in this Regulation:*

Provided that the Commission, based on review of the operation of SRAS, may direct procurement of SRAS through market-based bidding mechanism to be specified separately.

(2) *An SRAS Provider willing to participate in SRAS shall be required to provide standing consent to the Nodal Agency for participation, which shall remain valid till it is modified or withdrawn:*

Provided that standing consent cannot be modified or withdrawn without giving notice of at least forty-eight hours.

(3) *The SRAS Providers that are generating stations, shall be required to declare in such time interval as may be stipulated in the Detailed Procedure, the technical parameters as required by the Nodal Agency, including but not limited to installed capacity, Technical Minimum, Ramp up and Ramp down capability.*

(4) *The SRAS Providers other than the generating stations, shall be required to declare the technical requirements as may be stipulated in the Detailed Procedure.*

(5) *The SRAS Providers that are generating stations, shall declare their variable charge upfront on monthly basis in the manner as stipulated in the Detailed Procedure.*

(6) *The SRAS Provider other than the generating stations, shall be required to declare the compensation charges upfront on monthly basis in the manner as stipulated in the Detailed Procedure.*

(7) *The Nodal Agency, based on the estimate of the SRAS requirement as per Regulation 6 of these regulations, shall ascertain availability of adequate reserves on day-ahead basis and on real-time basis before the gate closure of the Real Time Market.*

(8) *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,*

(a) on day-ahead basis, based on the capacity available after the schedule has been communicated at 2300 hrs for the next day; and

(b) on real-time basis before the gate closure for incremental SRAS requirement"

Comments Received

A. Clause 1Procurement Mechanism

7.2 **MP Ensystems**, **Enel Green** requested market-based mechanism for SRAS right away instead of waiting for its roll-out at a later date.

7.3 **POSOCO** proposed that in the Ancillary Service Regulations all the ISGS stations whose tariff is determined or adopted must be made to mandatorily participate in SRAS. Some stakeholders (**Tata Power, CESC,Dhariwal Infra**) also asked whether the participation in the SRAS mechanism is voluntary or mandatory.

B. Clause2 3 & 4:Standing Consent and Technical Parameter

7.4 **Tata Power** sought clarification whether the generator has to take consent of the beneficiary under a PPA before providing concurrence to the Nodal Agency. **Tata Power** also requested clarification regarding beneficiaries losing right to recall in case a generating station is identified on day ahead basis. Tata Power sought clarification whether an ISGS under Section 63 of the Act can always choose not to participate in the SRAS mechanism. Tata power requested for clarification as to whether there is any penalty for the SRAS provider if it is not able to deliver at the right time or has to withdraw its consent at the last moment due to any unavoidable circumstances. Tata Power also requested whether there would be a provision of sharing of net profits on account of SRAS participation, if any, with the beneficiary.

7.5 **Sterlite Power** sought clarification on the capacity and duration for which the SRAS Providers' consent for participation will be valid. They also submitted that the SRAS Providers may be allowed to specify specific time slots for consent, along with the technical parameters sought and there should be a provision of revising the same on a monthly/yearly basis.

7.6 **POSOCO** suggested that there should be separate declaration formats of technical and commercial parameters for different types of resources such as Thermal, Hydro, BESS, Demand Side Response etc.

7.7 Some stakeholders (**Indi Grid Trust, AES**) suggested to bring certainty about the review period.

7.8 Some stakeholders *(***Greenko, RPG Power Trading , CESC Ltd., Dhariwal Infra Ltd. Renew Power, Indie Grid Trust)** sought clarification regarding consent and timeline for withdrawal notice and the events with technical fault or tripping or outages**.**

C. Clause 5 & 6: Energy Charge and Compensation Charge

7.9 **NHPC** commented that for hydro power plants, there is no concept of "Variable charges" – AFC of a hydro generating station is recovered in two parts viz. "Capacity Charge" and "Energy Charge" and suggested that the variable charges may be defined as Energy Charge Rate (ECR) plus water usage charges (additional energy charges).

7.10 **Greenko** submitted that capability of providing SRAS-UP service and SRAS-DOWN service differs for various technologies, hence they cost differently. All providers value secondary reserves differently in various time slots and the same needs to be allowed in the Regulations while declaring variable/compensation charges (such flexibility has been provided in TRAS procurement).

7.11 **Indi Grid Trust** sought clarity on whether Energy Storage and Demand Response can declare compensation charge unilaterally or a special Petition is required to be filed for determination or adoption of such Charge before the Commission.

7.12 **PCKLGreenko** suggested that a mechanism for ascertaining the actual price of eligible entity having energy storage resource or demand side resource needs to be addressed.

7.13 **Renew Power** proposed that Energy Storage needs to be incentivized as being a new and emerging technology and therefore, they should be allowed to quote a different price for UP and DOWN services and also a different cost on TOD slot basis.

7.14 Some stakeholders **(BYPL, Indi Grid Trust)** sought further clarity on compensation charge for BESS and DRs.

7.15 Some stakeholders (**Sterlite Power, Dhariwal Infra, Indi Grid Trust**) expressed concern about declaring variable or compensation charge upfront one month in advance.

7.16 Some stakeholders (**Greenko, CSTP, NHPC, PCKL, Dhariwal Infra Ltd. Sterlite Power, CER IIT Power)** expressed concern over change in VC due to the Heat Rate, GCV, Auxiliary Consumption and any associated cost implicationwhile some **(MB power Madhya Pradesh)** suggested that there should not be any retrospective revision in VC.

7.17 **NTPC, CESC RPG Power Trading,CER IIT Kanpur**sought clarity on the variable charge and energy charge and whether generators would be free to quote variable charge more than energy charge.

7.18 Some stakeholders (**CESC, Asit Singh, ERPC, NTPC, BYPL**) sought clarification on which basis an eligible generating station is identified as an SRAS Provider on day- ahead / real-time basis.

D. <u>Clause 7 and 8: Advance estimation of requirement on day ahead basis</u>

7.19 **NTPC** and **Shri Asit Singh** submitted that the actual availability of URS power from Section 62 Generators can be known only after the completion of auction and finalisation of results in the Real Time Market. Hence identification of stations can happen only after the results of RTM are finalised.

7.20 **Shri Asit Singh** also suggested that if some margin has to be kept for SRAS reserve, it should be with NOC else it should be with fixed cost liability.

7.21 **CEEW** sought clarification onthe timeline for identifying Secondary Reserve Ancillary Services (SRAS) with respect to the gate closure of the Real-Time Market (RTM), and whether this will override the right to recall of original beneficiaries

7.22 **Enerl green** suggested that SRAS obligation should not be limited to projects operating under section 62 but also for conventional projects operating under section 63

Analysis and Decision

7.23 As regards the mechanism of procurement of SRAS, the Commission is of the view that SRAS is being introduced for the first time in the country, and as such it is important to understand different operational and technical challenges in deployment of secondary reserves in the Indian power sector through administrative mechanism before moving to market-based procurement.

7.24 As regards Secondary Reserves, the Commission vide Order dated 28.08.2019 in Petition No. 319/RC/2018 directed that all Inter-State Generating Stations (ISGS) should be AGC enabled. Post the directive of the Commission, a total of 94 ISGSs 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. In view of this, the Commission has decided to go ahead with administrative mechanism for procurement of secondary reserves from amongst the eligible entities willing to participate. Accordingly, Regulation 9(1) has been retained as proposed in the draft Regulations.

7.25 It is important that the Nodal Agency has sufficient time to prepare stack of eligible SRAS providers well in advance. Hence, notice period of at least forty-eight hours for withdrawing the consent as proposed in the draft Regulation has been retained, but with the exception of forced outage of a generating station. In other words, in case of forced outage, the forty-eight hour condition shall not apply. However, it is also important that in such an event the generating station should inform the Nodal Agency immediately.

7.26 As regards the technical details, the Commission has directed that the Nodal Agency should provide separate declaration formats for technical and commercial parameters for different types of resources such as Thermal, Hydro, BESS, Demand Side Response etc. As regards the consent from the associated beneficiaries and any sharing mechanism of benefits, the Commission would like to clarify that it is outside the purview of these regulations. Accordingly, the Commission has decided to retain the Regulation 9 (3) as proposed in the draft Regulations.

7.27 As regards the declaration of variable charges or compensation charges, the Commission would like to clarify that a generating station whose tariff has been determined under Section 62 of the Act needs to declare its energy charge upfront on monthly basis as determined under Section 62 of the Act. The Commission has proposed this provision in line with the existing practice followed under existing RRAS Regulations. Other eligible SRAS providers including energy storageand demand side response, may decide to declare their compensation charge upfront as per their own assessment. The Commission does not feel it necessary to provide any cap or norms at this stage for declaration of compensation charge by such eligible SRAS providers. The Commission believes that custom participation factor would ensure that the efficient and cost-effective SRAS provider is deployed.

7.28 As regards the identification of generating stations in advance, the Commission would like to reiterate that it is important to continually assess the availability of secondary reserves in the system to take care of any contingency or system imbalance. Accordingly, the Nodal Agency shall identify the generating stations whose tariff is determined by the Commission under Section 62 of the Act for providing SRAS after considering the existing practice of scheduling and dispatch. This would help the Nodal Agency to assess the possible generation capacity in advance which can be made available for deployment based on the actual availability of such capacity after declaration of RTM results. This has been suitably clarified by adding a proviso to Regulation 9 (8) in the final Ancillary Services Regulations, 2022.

7.29 As SRAS would be deployed closer to real time from the available generation capacity in the eligible SRAS providers after such providers have exhausted all possibilities of energy scheduling, the Commission has decided that no commitment charge would be provided to eligible SRAS providers. However, the Commission has also decided that based on review of the performance of SRAS providers, appropriate compensation may be provided to SRAS providers to commit SRAS capacity in advance. Accordingly, a new clause 9 in Regulation 9 has been added in the final Regulations as follows:

> *"(9) There shall not be any commitment charge for the SRAS providers for the capacity ascertained under clause (7) or identified under clause (8) of this Regulation, but not signalled for SRAS:*
>
> *Provided that the Commission based on review of the availability and performance of SRAS, may provide for a mechanism for the SRAS Providers to commit SRAS capacity in advance, and also for appropriate compensation for such committed SRAS capacity."*

8 <u>Selection of SRAS Providers and Despatch of SRAS</u>

Commission's Proposal

8.1 The provision for selection of SRAS Providers was proposed as under in the Draft Regulations:

"***10. Selection of SRAS Providers and Despatch of SRAS***

(1) *SRAS Provider shall be selected on regional basis by the Nodal Agency for providing SRAS-Up or SRAS-Down based on the Custom Participation Factor.*

(2) *The Custom Participation Factor for each SRAS Provider shall be determined by the Nodal Agency based on the following criteria:*

(a) *Rate Participation Factor (Ramping capability in MW/min); and*
(b) *Cost Factor (variable charge or compensation charge, as the case may be).*

(3) *The Custom Participation Factor for SRAS-Up shall be directly proportional to the normalised Rate Participation Factor and inversely proportional to the normalised Cost Factor. The Custom Participation Factor for SRAS-Down shall be directly proportional to the product of the normalised Rate Participation Factor and normalised Cost Factor.*

(4) *Based on the above principle, Custom Participation Factor shall be calculated which shall be normalised to determine the participation of each SRAS Provider.*

(5) *SRAS signal shall be allocated among the SRAS Providers on regional basis to meet the SRAS requirement of the system based on the normalised Custom Participation Factor subject to the ramp limited resources available with the SRAS Provider(s).*

(6) *The Custom Participation Factor shall be calculated as specified in* ***Appendix-I*** *of these regulations.*

(7) *SRAS shall be despatched on regional basis through secondary control signals by the Nodal Agency.*

(8) *Secondary control signal for SRAS-Up and SRAS-Down shall be sent to the control centre of the SRAS Provider every 4 seconds by the Nodal agency. SRAS Provider shall allow its control centre to follow the secondary control signal for SRAS-Up or SRAS-Down automatically without manual intervention.*

(9) *The SRAS Provider shall increase or decrease active power injection or increase or decrease drawal or consumption, as the case may be, as per the automatic signal from the Nodal Agency.*

(10) *The SRAS Provider shall share real-time data with NLDC and the concerned RLDCs as stipulated in the Detailed Procedure.*

(11) *Average of SRAS-Up and SRAS-Down MW data shall be calculated by the Nodal*

Agency for every 5 minutes in absolute terms using archived SCADA data at the Nodal Agency and reconciled with the data received at the control centre of the SRAS Provider and shall be used for payment of incentive as per Regulation 12 of these regulations.

(12) *Average of SRAS-Up and SRAS-Down MW data shall be calculated for every 15 minutes time block in MWh for every SRAS Provider by the Nodal Agency using the archived SCADA data at the Nodal Agency and reconciled with the data received at control centre of the SRAS Provider and shall be used for payment of variable charge or compensation charge, as the case may be, to the SRAS Provider as per Regulation 11 of these regulations."*

Comments Received

8.2 On selection of SRAS provider based on custom participation factor, **NTPC** suggested that instead of apportionment of the total requirement among all the resources, it should be done **on basis of stacking order**, based on cost considerations.

8.3 **APMuL and Sterlite** requested dispatch algorithm and proposed that the SRAS provider with the highest Normalised Custom Participation Factor (NCPF) be dispatched to its maximum ramp limited capacity and the rest of the SRAS requirement be filled by the second highest NCPF SRAS Provider and so on.

8.4 **Wartsila,CSTP** suggested fast ramping resources should be incentivized with capacity charges for committing the resources for providing such services.

8.5 **CER-IIT Kanpur** suggested to include ramping rate (in %) rather than in absolute term (MW/min) to provide correct incentive to deploy faster ramping resources.

8.6 **Torrent Power Ltd** requested to revise the clause to accommodate the technical minimum of the SRAS provider.

8.7 Some stakeholders (**IIT Roorke, CER- IIT Kanpur, CSTP, Wartsila, Sterlite Power, APMuL**) expressed concern over normalised custom participation factor (NCPF) and felt it is inadequate. Some others (**PCKL, CEEW, Torrent Power**) highlighted that Custom Participation Factor (CPF) for an entity having energy storage resource or demand side resource is not clearly specified in these regulations. Some stakeholders (**POSOCO, RPC, CER IIT Kanpur**) suggested modification and alternative method for allocation of SRAS signal.

8.8 **POSOCO** suggested additional provision for 'Local' operation and 'Remote' operation by SRAS Providersas per the guidelines furnished in the Detailed Procedure and modalities of exchange data in case of events such as communication failure, scheduled maintenance etc. According to POSOCO, SRAS Providers would also need to submit the required undertaking before the start of Closed Loop Tests with the Nodal Agency.

8.9 **MSEDCL** suggested that the energy meter data for 15 minutes being available, their accounting should be done using the SEM instead of SCADAdata. It has also been suggested that meter capable of recording 5 minute integration period should be procured and installedon priority on these interface points.

8.10 **PCKL** commented that for the purpose of performance of SRAS, the SCADA data is used and for deviation accounting, actual meter data is considered. Hence, clarification is required as there may be difference in SCADA (Real Time data) & actual meter data.

8.11 **ERPC** commented that the SCADA system is inherently sluggish in nature and most of the utilities do not find them to be reliable for the purpose of managing their deviations from schedule. It is, therefore, suggested that for fast and reliable communication network between SRAS provider and the Nodal agency, Automated Meter Reading (AMR) based real time telemetry system or Optical fiber communication network may be explored.

8.12 **RPG, CESC** suggested reconciliation of energy for incentive payment proposed in 5-minute blocks instead of 15-minute blocks.

8.13 **ERPC** sought clarification as to how the consumption of the drawl entity would be controlled as sudden load increment and load shedding may not be possible, since the drawl entity is also eligible for being SRAS provider in response to the control signal from the system operator. Furthermore, ERPC has also submitted that there could be a contradiction between the SRAS (Up/Down) instruction and the sign change violation to manage deviation from their drawl schedule**.**

8.14 According to some stakeholders (**SRPC, Greenko, Wartsila, IIT Kanpur)** the existing mechanism does not capture fast responding resources and sought clarification on the methodology in this regard in respect of entities having energy storage resource or demand side resource.

8.15 Some stakeholders (**MSEDCL, Statekraft, PCKL, ERPC**) said meter data instead of SCADA data should be used.

8.16 Some stakeholders (**RPG Power Trading, PCKL, CESC Ltd)** sought clarification about state embedded SRAS providers and about sharing of data from SLDC to RLDC.

8.17 Some stakeholders (**CESC Ltd. , CER IIT Kanpur, POSOCO**) sought clarification on modus for allocation of SRAS signal among the identified SRAS providers along with clarification on network congestion aspects during dispatch of SRAS.

Analysis and Decision

8.18 The Commission has noted the suggestions of the stakeholders regarding Normalised Customised Participation Factor (NCPF) and is of the view that the proposed mechanism of considering ramp-rate and cost-factor, adequately captures the need for fast ramping resources while taking into account the cost optimisation in SRAS deployment. It is believed that this proportionate dispatch algorithm for dispatch would be an economically efficient way of utilizing the SRAS Services. As regards to the suggestions on modalities of NCPF in case of energy storage and demand side resources, the Commission has decided the same would be illustrated in the Detailed Procedure by the Nodal Agency with relevant examples based on consultation with the stakeholders. Accordingly, the Commission accepts the suggestion of the POSOCO that Annexure-1 may not be required as a part of the Regulation and the same would be provided with desired clarity in the Detailed Procedure of the Nodal Agency.On the suggestions of modalities of data exchange in events such as communication failure, scheduled maintenance etc., the Commission has decided that the same would be stipulated in the Detailed Procedure by the Nodal Agency. Similarly, modalities of the drawl entity as SRAS providers would be detailed out in the Detailed Procedure while ensuring the existing practice of scheduling and accounting with inter-state and intra-state entity.

8.19 On the issue of using SCADA data, the Commission would like to reiterate that the international experience establishes the use of SCADA data for secondary response. Further, sufficient experience has been gained regarding measurement aspects of secondary control signal through SCADA and Energy Management System under AGC pilot in India. Since, the SRAS is a MW regulation service and no energy meter can capture secondary control signal in 4 seconds, the Commission would like to retain the provision of SRAS accounting based on SCADA data. The Commission has 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 and then subsequently to provide reference for meter data based on 15-minute time block forassessing the deployment underSRAS.

8.20 As regards the clarification on capturing 5-minutes and 15-minutes data as provided in Clause 11 and Clause 12 of Regulation 10, the Commission is of the view that 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, as this is necessary to capture both SRAS-Up and SRAS-Down service by the SRAS Provider, for the purpose of incentive calculation. At the same time, average of 5-minute data would be net of SRAS-Up and SRAS-Down to estimate the energy contribution on account of SRAS. 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. Accordingly, the Commission has decided to retain the provision in the Clause 11 and Clause 12 of Regulation 10 as proposed in the Draft Regulations.

9 <u>Payment for SRAS</u>

Commission's Proposal

9.1 Mechanism for payment for Secondary Reserve was proposed as underin the Draft Regulations:

*"**11 Payment for SRAS***

(1) *SRAS Provider shall be paid from the Deviation and Ancillary Service Pool Account, at the rate of their variable charge or compensation charge, as declared by the SRAS*

Provider, as the case may be, for the SRAS-Up MW quantum despatched for every 15 minutes time block, calculated as per clause (12) of Regulation 10 of these regulations.

(2) *SRAS Provider shall pay back to the Deviation and Ancillary Service Pool Account, at the rate of their variable charge or compensation charge, as the case may be, for the SRAS-Down MW quantum despatched for every 15 minutes time block, calculated as per clause (12) of Regulation 10 of these regulations.*

(3) *SRAS Provider shall be eligible for incentive based on performance as per Regulation 12 of these regulations.*

(4) *Methodology of computation under clauses (1) to (3) of this Regulation shall be stipulated in the Detailed Procedure."*

Comments Received

9.2 **Dhariwal Infra** sought clarification on whether the reconciliation of energy for incentive payment proposed in 5minute blocks would be in line with 15 minute blocks.

9.3 Some stakeholders **(CEEW, BYPL)** also commented that the costs and benefits of transitioning to a 5-minute scheduling and despatch system need be assessed**.**

9.4 **RPG, CESC** sought clarification whether payment of commitment charges to the generator can be allowed in case of SRAS if there is no actual despatch of the power, as is allowed in the case of TRAS.

9.5 **MPPMCL** suggested that SRAS Provider should be paid at the rate of their variable charge or compensation charge along with the Fixed Charge as approved by the Commission and the fixed charges shall be adjusted to the original beneficiaries for the quantum of Un-Requisitioned Surplus scheduled under Regulation Up Service.

9.6 **MB Power** suggested to identify a separate pool/ source towards meeting the working capital requirement and operationalizing the payment and settlement of SRAS and TRAS Providers.

9.7 **Tata Power** suggested that during SRAS down instruction, the participating entity, especially if it is a thermal generator, must be compensated for degradation in operational norms, if any.

9.8 **PCKL** suggested that SRAS provider should not pay back to the Deviation and Ancillary Service Pool Account, at the rate of their energy charge or compensation charge. Rather, there should be incentives as they are providing the support to the grid.

9.9 **SRPC** has suggested that the data should be frozen subsequent to the reconciliation by Nodal Agency and SRAS provider and further revisions of SCADA data by the SRAS provider should be strictly avoided.

9.10 **Greenko** suggested that either an alternate source of funding to the AS Providers in case of insufficient fund in the Regional Deviation Pool Account Fund (apart from other regional deviation pool accounts) may be prescribed in the Regulations, or 'Causers Pay' approach may be considered as is the case with many international AS operators like AEMO.

9.11 **Renew Power** suggested that as proposed for TRAS, a commitment compensation structure should also be put in place for SRAS to promote adoption of new technologies and to bring efficiency to the market.

9.12 **NHPC** submitted that energy charge billed tobeneficiary DISCOMs should be used for payment to SRAS provider especially in case of hydropower stations where ECR is greater than Rs 1.20/kWh.

9.13 **Shri Asit Singh** proposed that, to take care of part load compensation charge, the SRAS Provider should pay back to the Deviation and Ancillary Service Pool Account, at the rate of their 90% of variable charge or compensation charge, as the case may be.

9.14 **Greenko** proposed incentives in the form of mark-up for providing AS from RE sources.

9.15 **Dhariwal Infra** stated that there is a need to provide a higher rate of performance-based incentive to the generators providing the SRAS-Down service, as generators, while reducing the load will be affected by deteriorating heat rate, higher O&M cost, requirement of support of oil for unit stabilization and other parameters on account of low loading factor etc. Further, incentivization of the generator will provide them with better opportunities to make themselves available as SRAS providers.

9.16 **Shri Sangeet Dave** proposed not to differentiate between SRAS-Up and SRAS-Down. According to him CPF for "SRAS-UP" will go in favour of hydro and battery storage while "SRAS- Down" will favour thermal generating stations due to design of Custom participation factor (CPF). Hence this will act as penalty for thermal stations to bring back frequency to 50 Hz by PRAS and SRAS.

9.17 Some stakeholders (**Ekniti, AES,Greenko, PCKL, US-ISPF, MP Enystems, CESC Ltd.**) suggested that there should be some minimum guaranteed capacity charge for both the SRAS and TRAS for maintaining the capacity and recovering the operational cost plus a premium for gradual recovery of Capex.

9.18 Some stakeholders (**MP Power Management Co. Ltd., Asit Singh, Tata Power, ERPC, CER IIT Kanpur**) suggested that fixed charges should be adjusted to the original beneficiaries for the quantum of Un-Requisitioned Surplus scheduled under Regulation Up Service**.**

Analysis and Decision

9.19 As regards the issue of using 5 minutes metering system, the Commission is of the view 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. The same methodology of recording and measurement of secondary control signals was used in the implementation of AGC pilot with a few selected ISGSs. Hence, the Commission has decided to retain the provision of SRAS payment based on quantum dispatched in each15 minutes.

9.20 On the issue of providing mark upto SRAS provider as commitment charge, the Commission would like to reiterate that SRAS would be deployed closer to real time from the available generation capacity in the eligible SRAS providers after all other possibilities of dispatch under the existing scheduling process are exhausted. As such, the Commission has decided that no commitment charge would be provided to the eligible SRAS providers. However, the Commission has also decided that based on review of the performance of SRAS providers, appropriate compensation may be provided to SRAS providers to commit SRAS capacity in advance.

9.21 As regards the concerns that CPF may favora specific technology, the Commission is of the view that the proposed principle of NCPF would ensure that the efficient and cost effective SRAS provider is dispatched. The methodology of computation would be elaborated in the Detailed Procedure.

9.22 On the question of adjustment of fixed charge of the beneficiaries, the Commission is of the view that the same is outside the purview of these regulations and hence not considered.

9.23 As regards the requirement for paying back to the deviation and ancillary pool account bySRAS Provider in case of SRAS-down, the Commission would like to clarify that the rationale behind such a provision is that such generators would have received the energy charge based on their schedule and hence would pay back to the pool account corresponding to their SRAS Down contribution calculated over average of 15minutes. It is believed that the contribution in SRAS down would be relatively small for any generating entity as compared to their overall schedule and hence the incentive receivable towards performance of such SRAS provider, which is estimated with absolute contribution in 5 minutes interval, would be sufficient to encourage them to participate in SRAS. In fact, even in a situation where the SRAS provider might have contributed zero MWh during any specific 15-minute time block, such SRAS provider shall be entitled to incentive for its contribution by measuring SRAS Up and SRAS Down in absolute terms for the purpose of incentive calculation. This is meant to recognize and reward the performance irrespective of the energy delivered by the SRAS provider.

10 <u>Performance of SRAS Provider and incentive</u>

Commission's Proposal

10.1 The provision relating to Performance of SRAS Provider along with incentive was proposed as underin the Draft Regulations:

*"**10. Performance of SRAS Provider and incentive***

(1) The actual response of SRAS Provider against the secondary control signals from the

Nodal Agency to the control centre of the SRAS Provider shall be monitored by the Nodal Agency, as per the procedure stipulated in the Detailed Procedure.

(2) All measurements of secondary control signals from the Nodal Agency to the control centre of the SRAS Provider and actual response of SRAS Provider shall be carried out on post-facto basis using SCADA data. Performance of the SRAS Provider shall be measured by the Nodal Agency by comparing the actual response measured against the secondary control signals for SRAS-Up and SRAS-Down sent every 4 seconds to the control centre of the SRAS Provider. The methodology for measurement of performance of SRAS Provider shall be as specified in Appendix-II of these regulations.

(3) SRAS Provider shall be eligible for incentive based on the performance measured as per clause (2) of this Regulation and the 5-minute MWh data calculated for SRAS-Up and SRAS-Down as per clause (11) of Regulation 10 of these regulations and aggregated over a day, as under:

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

”

Comments Received

10.2 **POSOCO** commented that **20% minimum performance benchmark** is **too low**. There is a need to raise the threshold level to **at least 50 %** for getting the desired response. The bands of actual performance vis-à-vis secondary control signal for an SRAS Provider could be made simpler to begin with and gradually tightened over time.

10.3 **NLCIL** suggested that the proposed ceiling for performance-based incentive of 40 paise/kWh for SRAS Providers, being lower than the current mark-up of 50paise/kWh, may be enhanced.

10.4 **NTPC** proposed that the incentive slabs/ rate under Performance Measurement scheme may be designed based on the actual performance data of around 6 months. Till that time, mark-up of 50 paise/kWh may be continued.

10.5 **POSOCO** commented that maintaining and retrieving 4 seconds data and backups transparently for the purpose of performance-related calculations can be challenging in the long run. The 5 minutes average data would have the advantages over 4 seconds data in terms of lesser memory usage (KB vs MB), fast retrieval and smoothened over 5 minutes, thereby avoiding inevitable SCADA noise. 5 minutes data usually results in 1%-5% better (optimistic number) performance as a result of smoothening.

10.6 **MSEDCL** submitted that generators will normally achieve performance of >90% as they generally receive signal through strong communication network. Furthermore, since performance is being calculated on a Day basis and not for each 5 minute time block, incentive may be capped at 20 paise/kWh instead of 40 paise/kWh (starting with 5 paise/kWh for 20% to 45%).

10.7 **BYPL** submitted that there is no penalty of non-performance or less performance. As such, the performance below 60% should not be incentivized. Further the incentive rate of 40 paise/kWh is very high. The basis of incentive of 40 paise/kWh needs to be explained.

10.8 **NTPC** commented in the context of incentive mechanism that after the rollout of Pilot AGC in five NTPC stations, it has been observed that at times RGMO correction and AGC correction sent by POSOCO can be opposite to each other, negating each other's correction. This is because RGMO is triggered by variation in frequency, while SRAS is triggered by ACE taking in account both frequency variations and the regional power interchange. In such a case, the station would appear to be delivering inadequate response at both fronts during assessment by the Nodal Agencies and the same needs to be taken care in the assessment procedure.

10.9 **Shri Asit Singh** proposed that even for TRAS-Down, the provider has to keep margin and hence, may be paid commitment charge of 5 paise/kWh.

10.10 **Greenko** requested the Commission to provide a sample calculation with real data for a day (downloadable) deriving the performance and incentives payable.

10.11 **MPPMCL** proposed that incentive gained by the SRAS Provider under the Regulation may be shared with the original beneficiary in the 50:50 ratio or as deemed fit by the Commission**.**

10.12 According to **CER- IIT Kanpur,** the scale of proposed incentive in draft regulation seems to be disproportionately high and will impose significant burden, particularly on distribution utilities. Considering the fact that generators are already provided various incentives and IEGC mandates system constituents to follow the system operator's instructions, it is suggested that the scale of incentives should be replaced with a scheme of penalty and incentive. Alternative scheme of incentive and penalty was proposed as follows.

Actual performance vis-à-vis secondary control signal for an SRAS Provider	Proposed Incentive Rate (paise/kWh)	Suggested Incentive / Penalty Rate (paise/kWh)
Above 95%	(+) 40	(+) 15
70-95 %	(+) 30	(+) 10
45-70%	(+) 20	00
20-45%	(+) 10	(-) 05
Below 20%	0	(-) 10

10.13 **US-ISPF** commented that it would be helpful if details on determination of incentive structure and the speed of response/formula considered could be provided for a better understanding. Further, it is suggested that the structure can propose penalty for non-performance along with incentives for performance. According to US-ISPF the effectiveness of the incentive structure will be fully utilized when it is applied to PRAS as well and on linking with faster response time in PRAS and SRAS.

10.14 Some stakeholders **(NLC Tamil Nadu Power Ltd.)** also suggested higher band for performance with different incentive rates for peak hours and non-peak hours**.**

10.15 Some (**NTPC, Greenko, IRADe, IIT Roorki, Tata Power , Fluence , Ekniti India Pvt Ltd, NLC India, CESC Ltd. Dhariwal Infra Ltd., Renew Power, Enel Green**)commented that the incentive is not enough and advocated higher incentive (at least 50 paise/kWh)for storage and other new technologies.

10.16 Some stakeholders (**Tata Power, RPG Trading Company, BYPL**) suggested that there should also be penalty for non-performance.

10.17 Some stakeholders (**CER IIT Kanpur, POSOCO, ERPC***)* sought clarification on the Appendix and suggested alternative approaches.

Analysis and Decision

10.18 As regards the suggestion of performance assessment based on 5-minutes average data instead of 4 seconds data, the Commission would like to clarify that since the SRAS signals would be sent every 4 seconds and stored at the Nodal Agency, the same should be used for performance assessment. Modalities in this regard to capture actual performance of SRAS provider against the secondary control signal should be monitored as per the Detailed Procedure to be stipulated by the Nodal Agency.

10.19 As regards the threshold limit for incentive, the Commission has taken a liberal approach towards the performance of SRAS Providers as SRAS is being introduced for the first time in India. Further, in view of the concern raised by some stakeholders, the Commission has decided to modify the slabs proposed in the Draft Regulations such that maximum incentive up to 50 paise/kWh may be payable to such SRAS Providers which have performed above 95%. The Commission believes that this will provide adequate incentive for participation in the SRAS while keeping liberal approach by providing minimum incentive of 10 paise/kWh for performance between 20% to 50%. On the same line, the Commission has decided not to provide any penalty for SRAS at this stage.

10.20 The details of performance assessment would be elaborated in the Detailed Procedure based on the principle specified in Clause (2) of the Regulation 12. It is clarified that the principles specified in this Regulation are based on the feedback received fromPOSOCO on the AGC pilot. Accordingly, the principles of calculating the incentive payment have been specified in the newClause (4) of Regulation 12 in the final Ancillary Service Regulations, 2022. On the issue of calculating the incentive payment for SRAS provider other than generating station, the Commission has decided that the same would be elaborated in the Detailed Procedure by the Nodal Agency with due regard to the principle specified in Clause (4) of the Regulation 12.

11 Regulation 13: Failure in performance of SRAS

Commission's Proposal

11.1 The mechanism in case of failure in performance including violation of direction of Nodal Agency by SRAS Provider was proposed as underin the Draft Regulations:

*"**13.Failure in performance of SRAS***

(1) *Performance below 20% for two consecutive days by an SRAS Provider shall make the SRAS Provider liable for disqualification for participation in SRAS for a week by the Nodal Agency.*

(2) *Violation of directions of the Nodal Agency for SRAS under these Regulations shall make the SRAS Providers liable for penalties as per the provision of the Act."*

Comments Received

11.2 **CESC** sought clarification on the modalities of under performance by SRAS provider in any day when no SRAS is required vis a vis the nextday when SRAS is required.

11.3 **SRPC** suggested that incentive for performance below 45% after two consecutive days by an SRAS provider may be reduced to zero from the third day and incentive may be restored if it perform subsequently at 45% or above.

11.4 **Enel Green** suggested that minimum performance period be extended to atleast 24 hours beyond such minimum time limit to withdraw standing consent which is currently stipulated as forty-eight hours.

11.5 **CESC and RPG** submitted that the violations/ deviations by any SRAS provider might occur due to any technical reasons not attributable to the service provider e.g. communication/ SCADA related issues of data exchange between the generator and Nodal Agency. Hence, this clause may be suitably modified with more clarity, so that SRAS participants are not unduly penalized for any violation for reasons not attributable to the SRAS provider.

11.6 **Wartsila** suggested that the proposed regulation should also impose financial penalty on the service provider for not being able to fulfil its obligation in addition to disqualification for participation.

Analysis and Decision

11.7 The Commission has taken a liberal approach in specifying the disqualification of SRAS provider as SRAS mechanism would be implemented for the first time in India. 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 from participation in SRAS for a week. Further, in order to bring discipline and to ensure smooth implementation, the Commission has specified that any violation of direction of the Nodal Agency would be liable for penalties as per the provision of the Act. As regards the modalities of assessing the failure in performance, the Commission is of the view that the Nodal Agency would cover all possible situations to assess the performance failure in its Detailed Procedure.

Part II: Tertiary Reserve Ancillary Service (TRAS)

12 Regulation 14: Eligibility for a TRAS Provider

Commission's Proposal

12.1 The provision relating to eligibility forTRAS Provider was proposed as underin the Draft Regulations:

> *"**14. Eligibility for a TRAS Provider***
> *A generating station or energy storage resource or demand side resource connected to inter-State transmission system or intra-State transmission system shall be eligible for participation as TRAS Provider, if*
> *(a) it is capable of varying its active power output or drawl or consumption, as the case may be, on receipt of despatch instructions from the Nodal Agency; and*
> *(b) it is capable of providing TRAS within 15 minutes and sustaining the service for at least next 60 minutes."*

Comments Received

12.2 **POSOCO** commented that there should be provisions to measure and monitor non-delivery of TRAS as there is scope for gaming by TRAS providers.

12.3 **Shree P.K. Aggarwal** proposed that regulation should include some provision to keep check on the available capacity or verifying the capacity offered in TRAS to stop any gaming.

12.4 **CESC and RPG** sought clarification if Discom as a pooled entity shall be eligible to participate as TRAS provider or whether the embedded sources/assets within the Discom shall be treated as separate TRAS provider(s). RPG also sought clarification whether willing RE generators (wind, solar, bagasse, biomass, small hydro etc.) are also eligible to participate. Further clarification has been sought – if URS power of any generator can also bid in TRAS on real time basis in disregard to RTR for the beneficiary.

12.5 **Shri Sangeet Dave** sought clarification as whether TRAS provider can withdraw its support after mandatory 60 minutes one way information to NLDC with no strings attached.

Analysis and Decision

12.6 The Commission is of the view that the proposed eligibility criteria for TRAS are adequate and based on the experience gained in implementation of the existing RRAS Regulations. Hence, the Commission has decided to retain the same provision with minor editorial modification.

12.7 As regards the suggestion of specifying the verification methodology for the minimum 60 minutes capability of the TRAS provider, the Commission is of the view that the required verification methodology may be covered in the Detailed Procedure of the Nodal Agency.

12.8 On the issue of participation of Discom as an entity to provide TRAS, the Commission is of the view that as long as such entity fulfills the eligibility criteria, there should not be any entry barrier for participation as TRAS Provider. The required checks and balances can be built in the Detailed Procedure to avoid any undue advantage or manipulation by any such entity. Accordingly, the Commission decided that the Nodal Agency should prepare the required technical and operational criteria for enabling such entity to participate as Ancillary Service Provider.

13 <u>Regulation 15: Activation and Deployment of TRAS</u>

Commission's Proposal

13.1 The provision relating to Activation and Deployment of TRAS was proposed as underin the Draft Regulations:

"TRAS shall be activated and deployed by the Nodal Agency on account of the following events:

(a) In case the 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;

(b) Such other eventsas specified in the Grid Code."

Comments Received

13.2 **BYPL** commented that the condition of activation and deployment of TRAS should be clearly specified in the Grid Code and there should be a system of regulatory oversight for verification of occurrences of such events.

13.3 **POSOCO** proposed to add following event in clause(b):

(b) Such other events as specified in the Grid Code as under:

- *Extreme weather forecasts and/or special day;*
- *Generating unit or transmission line outages;*
- *Intra-day load forecast or Trend of load met;*
- *Trends of frequency and area control error;*
- *The trend of the utilization of reserves through secondary frequency control.*
- *Any abnormal event such as an outage of hydro generating units due to silt, Coal*

supply blockade etc.;

- *Excessive loop flows leading to congestion;*
- *such other events*

13.4 **POSOCO** also emphasized the need for suitable market surveillance and monitoring mechanism to ensure that the generating station which is providing SRAS, TRAS and normal energy scheduling must declare uniform technical parameters across all the segments.

Analysis and Decision

13.5 On the issue of specifying the events for activation of TRAS, the Commission is of the view that activation criteria would be elaborated in the Grid Code while Ancillary Service Regulations would cover the provisions regarding procurement, deployment and payment of such services. The Commission is already in the process of review of Grid Code based on the report submitted by the Expert Group on Grid Code. Relevant provisions regarding activation criteria would be considered while finalizing the Grid code.

13.6 As regards the suggestion of regulatory oversight, the Commission is of the view that the required checks and balances can be built in the Detailed Procedure. On the issue of providing market surveillance and monitoring mechanism, the Commission is of the view that this is outside the purview of these regulations and relevant amendments may be considered in relevant Regulations as and when the Commission deems appropriate.

13.7 Accordingly, the Commission has decided to retain the provision proposed in the Draft Regulations.

14 <u>Regulation 16: Procurement of TRAS</u>

Commission's Proposal

14.1 Procurement of TRAS through Ancillary Service Market in the Day Ahead Market (DAM) and Real Time Market (RTM) segments of Power Exchanges was proposed as under:

*"**16. Procurement of TRAS***

(1) Buy Bid: The Nodal Agency shall communicate to the power exchange(s), the quantum of requirement of TRAS-Up and TRAS-Down on day-ahead basis before commencement of the Day Ahead Market and incremental requirement, if any, over and above the procurement in the Day Ahead Market, on real-time basis, before the commencement of the Real Time Market:

Provided that the quantum of requirement on day-ahead basis shall be communicated after considering the TRAS resources likely to be available on real-time basis.

(2) Sell Bid: The TRAS Providers shall submit bids in the following manner:

(a) Bids for TRAS-Up and TRAS-Down shall be submitted for each time block or for a minimum of two consecutive time blocks in the Day Ahead Market or in the Real Time Market.

(b) For TRAS-Up, Energy-Up bid in Rs./MWh shall be submitted for the offer volume in MW.

(c) For TRAS-Down, Energy-Down bid in Rs./MWh shall be submitted for the offer volume in MW.

(3) The capacity offered, as a sell bid in power exchange(s) for providing TRAS-Up or TRAS-Down from a resource in the same time-block, shall be separate and non-overlapping.

(4) The power exchanges shall collect the bids for TRAS-Up and TRAS-Down and share the same with the Nodal agency for price discovery in terms of Regulation 17 of these regulations.

(5) TRAS Provider cleared in the Day Ahead Market may place incremental bids in the Real Time Market. TRAS Provider not cleared in the Day Ahead Market or which has not participated in the Day Ahead Market, may also place bids in the Real Time Market."

Comments Received

A. Comments on Clauses 1 & 2

14.2 **NTPC** suggested that it would be better to conduct bidding through the portal of the Nodal Agency directly, avoiding the route of Power Exchanges.

14.3 According to **Torrent Power Ltd**., in addition to the Ancillary Market, the existing SCED and RRAS market should also be operated through Power Exchanges without any intervention of system operator.

14.4 **POSOCO** commented that Buy Bids by NLDC would be construed as trading activity and may be deleted.

14.5 On Demarcation between energy market (DAM/RTM) and TRAS Market (DAM/RTM), **POSOCO** proposed that bidding and clearing for TRAS (DAM) may be done post energy (DAM) clearing of day-ahead energy market. **Sterlite** suggested separate window for AS market in DAM and RTM.

14.6 **POSOCO** suggested that technical and ramping constraints of TRAS providers would need to be suitably considered at the time of bidding. Hence, suitable regulatory provisions would be needed keeping the grid security intact.

14.7 **IEX** suggested that NLDC should certify the eligibility of an entity based on which the entities should be allowed to submit their sell bids in the Ancillary Services Market. NLDC may also provide the process and necessary formats of certification in its Detailed Procedure.

14.8 **PXIL** requested to direct Nodal Agency to purchase TRAS quantum equally from the Power exchanges by communicating requirement of TRAS quantum simultaneously to the

Power exchanges.

14.9 **Statkraft** proposed that responsibility of managing Ancillary Reserves (AR) along with Real time matching and dispatch through market-based auctions must lie with the system operator itself.

14.10 **CESC** sought clarifications on whether there will be a separate market on power exchange for TRAS transactions or whether such TRAS bids will have a different identifier and the transactions will be carried out in the same Day Ahead Market / Real Time Market.

14.11 **SRPC** sought clarification on whether TRAS procurement will be on all India basis or Regional basis. It was also requested to clarify the procedure for estimation of TRAS quantum requirement on day ahead basis and suggested that the duration/period of the TRAS quantum requirement may be specified in the Detailed Procedure by the Nodal Agency.

14.12 **TATA Power, APMuL Sterlite Power** sought clarification on whether the TRAS provider has to take consent from its original beneficiary before participating in the TRAS DAM market because for entities having PPA or any other arrangement of tied up capacity, the first right of refusal is available with the beneficiaries of such PPA.

14.13 **Statekraft** sought clarity on allotment of TRAS among the PXs and process of conducting the bidding.

14.14 Since the participating entities may be members of various Power Exchanges, **CESC** suggested that there needs to be Market Coupling Operator to monitor and control TRAS**.**

14.15 **CER-IIT Kanpur**suggested that the two market contracts may be called as DAM-TRAS and RTM-TRAS to differentiate them from energy contracts.

14.16 **NTPC** sought clarification on the flow of information among the stakeholders in the Ancillary Market. NTPC expressed concerns over inability of participation of cheaper resources in DAM due to right to revision and costlier power from generating stations having merchant capacity would only be eligible for participation leading to increase in cost of procurement of AS and increase the system operation cost. NTPC suggested the alternative to utilize all the cheaper URS power available at the time of deployment and then deploying the cheaper power after comparing cost of the cost of URS power with the Market discovered price. NTPC has expressed concerns over utilization of gas stations under the proposed Ancillary Mechanism.

B. <u>Comments on Clauses 3,4 & 5</u>

14.17 **IEX** submitted that the responsibility of ensuring that 'there is no overlap between TRAS UP and TRAS DOWN capacity' should lie with the Service Provider and in case of any breach, it should be ascertained by the NLDC for any further action as the NLDC only would have the complete visibility of the overall scheduling of the plant.

14.18 **IEX** commented that as the Exchanges will be acting as per regulatory requirement only collecting the bids for the NLDC without acting as counterparty to the Ancillary contract, the Exchanges should be indemnified against any loss arising out of such transaction by NLDC & Ancillary Services Provider.

14.19 **IEX** suggested that Ancillary Market for TRAS may be called 'Day Ahead Ancillary Market' and 'Real Time Ancillary Market' to separate from the existing energy contracts in the same market. IEX has sought clarification on whether RTM session will be provided only on request of NLDC, or the sessions need to be available irrespective of NLDC's demand. IEX requested for clarity on bidding timelines and a broad structure and possibility of block bid in AS contract.

14.20 **PXIL** sought clarity on transaction fees and margin money in TRAS and mechanism to recover the same either through entity or through Pool account. PXIL also requested to devise appropriate risk management mechanism while operating the TRAS Contract.

14.21 **PXIL** commented that majority of participants are registered with both the Exchanges. In order to avoid misuse/gaming it should be clarified that the entity that is registered for participation in TRAS ensures that the combined total order placed for TRAS-Up or TRAS-Down for the same time-block on separate power exchanges should be within prescribed technical limits.

14.22 **NTPC** proposed that PXs should not charge any fees for Ancillary Market.

14.23 **CEEW** suggested that for specified daily windows in seasons when the Nodal Agency anticipates higher reserve requirement, bilateral procurement of SRAS and TRAS via reverse auctions ahead of time may help mitigate price risk.

14.24 **Dhariwal Infra** sought clarification on whether the bidding process undertaken on Day Ahead Market or Real Time Market shall mandatorily have to be carried out by a generator only or it can also involve a trader as per the present practice of bidding.

14.25 **MB power** Ltd stated that in view of concurrent operations of multiple Power Exchanges, it may be appropriately clarified whether bids for Ancillary Services would be cleared in all the Power Exchanges or a particular Power Exchange shall be designated for clearing bids for Ancillary Services.

14.26 **TATA Power** commented that there needs to be enough liquidity and depth in RTM so that an exodus of entities does not happen from RTM to TRAS market for TRAS-UP.It has also been submitted that two different markets for identifying TRAS sale quantum may lead to price distortion as entities may put different prices in RTM based on the result declared for DAM market. This may also result in unnecessary disbursement of commitment charges to the entity from the pool. It is proposed that TRAS bidding may initially be done in RTM only, as the real URS available would be visible to all concerned at this stage.

14.27 **AES India** requested to elaborate how the market sizing is done, and how it will be conducted to determine and plan potential of Ancillary service revenue streams.

14.28 **Shree P. K. Aggarwal** commented that the proposed TRAS market in DAM and RTM would create opportunity for the market participants for arbitrage and unnecessary gain to the participants as there is no cap on TRAS but on DSM price.

14.29 **POSOCO** sought clarification whether TRAS down bids can be used as an instrument for purchase of power from the grid by generators. There would be opportunity of arbitrage for the generators who participate in multiple markets in multiple time-frames.

14.30 Some stakeholders (**Tata Power, Fluence**) expressed concern over sufficient liquidity in the TRAS and also its impact on other markets.

14.31 Some stakeholders (**CESC, RPG**) emphasized the need of Market Coupling Operator to monitor and control TRAS.

Analysis and Decision

14.32 Some stakeholders requested for clarity on timelines for TRAS market along with flow of information among PXs and the Nodal Agency. Some stakeholders requested to implement the AS Market directly through web-portal at the Nodal Agency. Some stakeholders requested to indemnify the PXs against any loss arising out of AS transaction by NLDC & Ancillary Services Provider. Some stakeholders requested that Energy and Ancillary Service Market should be identified separately in the PXs. Some stakeholders requested for clarity on the timeline and bidding structures for TRAS Market.Some othersvoiced concern over liquidity of AS Market, while some stakeholders expressed concerns around possibility of arbitrage between energy and Ancillary Market. Some stakeholders suggested to remove price cap, while others asked to retain the same on similar line with the cap for DSM price. Some also suggested to link the DSM price with Ancillary Service to avoid any arbitrage between the AS Market and DSM. Some others also suggested the review of DSM mechanism and its linkage with frequency.

14.33 In order to address the concerns of stakeholders and to bring clarity on the time line for TRAS Market, the Commission has added in the final Ancillary Service Regulations, 2022, a separate provision that until specific provision is specified for timelines for TRAS Market in the Grid Code, the bidding timelines for Day Ahead AS Market and Real Time AS Market shall be the same as those of the Day Ahead Market for energy and Real Time Market for energy respectively. Accordingly, the Ancillary Service Market would be implemented as per the principles specified in these regulations and would be separate from the existing energy market. The Commission believes that the existing timelines of DAM and RTM energy market can also be applied to DAM-AS and RTM-AS markets. Accordingly, suitable modification has been made in Regulation 16 of the final Regulations. The Commission believes that same timelines will address the concerns of some stakeholders about possible arbitrage between energy and Ancillary Service (AS) Market. It is envisaged that each participant would choose appropriate strategy to either participate in the energy market or in the ancillary market or in both while ensuring that the same capacity has not been offered in both energy and AS market. Similarly, the capacity offered for TRAS-Up and TRAS-down should also be separate and non-overlapping. Required checks and balances in this regard would be elaborated in the Detailed Procedure by the Nodal Agency in consultation with Power Exchanges (PXs) and other stakeholders.

14.34 The Commission appreciates the concern raised by POSOCO to remove the text ‘Buy

Bid' so as to avoid it being construed as trading activity. Suitable modification has been made to this effect in the final Regulations. The Nodal Agency should only communicate the requirement of TRAS-UP and TRAS-down to all the operating Power Exchanges simultaneously before commencing the day-ahead market or real time market, as the case may be. Such time block wise demand information by the Nodal Agency would be for DAM and RTM separately. The Commission is of the view that this will bring transparency in the Ancillary Market which will ensure that an entity would participate in any market based on its own strategy and assessment of risk.

14.35 The Commission would also like to clarify that the eligible TRAS Provider should make its own assessment about its ramping capability while participating in the AS market with feasible quantum of sell bids.

14.36 As regards the allocation of quantum of TRAS among different PXs, the Commission does not find any rationale behind such a proposition. The Nodal Agency shall communicate total requirement of TRAS-Up and TRAS-Down to all PXs. The PXs would then collect the bids and transfer the same to the Nodal Agency for price discovery. Thus, it is envisaged that the Nodal Agency would discover the price of TRAS-Up and TRAS-down as per the price discovery mechanism specified in these regulations and would intimate the results to respective power exchange for further communication with cleared sell bids of respective PXs. The required protocol for exchange of information between the Nodal Agency and PXs would be stipulated in the Detailed Procedure by the Nodal Agency.

14.37 As regards the concerns of excess procurement of TRAS on Day Ahead basis, the Commission is of the view that the Nodal Agency should consider the possibility of any generation capacity to be available at real time before deciding the day-ahead procurement. The Commission believes that this provision would provide necessary checks and balances to make sure that the cheap resources if available in the system are utilised economically while ensuring grid security.

14.38 On the suggestion of Market Coupling and review of DSM, the Commission is of the view that the same is outside the purview of these regulations. Similarly, on the issue of fees of the power exchange and the bid structure, the Commission would like to clarify that the same would be decided at the time of approval of bye-laws and rules of the power exchange for AS contracts.

14.39 In view of the above discussion, Regulation 16 has been suitably modified in the final Ancillary Service Regulations, 2022.

15 Regulation 17: Price Discovery for TRAS

Commission's Proposal

15.1 For price discovery of TRAS, the following provisions were proposed in the Draft Regulations:

"***17. Price Discovery of TRAS***

Price Discovery for TRAS-Up

(1) The price discovery for TRAS-Up shall be based on the principle of Uniform Market Clearing Price.:

(2) The highest Energy-Up bid corresponding to the requirement for TRAS-Up as intimated under clause (1) of Regulation 16 of these regulations, shall be the Market Clearing price for Energy-Up in the Day Ahead Market (MCP-Energy-Up-DAM) or in the Real Time Market (MCP-Energy-Up-RTM), as the case may be.

Price Discovery for TRAS-Down

(3) The price discovery for TRAS-Down shall be based on the principle of Pay-as-bid.

(4) The Energy-Down bids shall be stacked 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) The Commission may, if considered necessary, provide for a price cap for TRAS"

Comments Received

15.2 **IEX** sought rationale for adopting a differential approach of price discovery in TRAS Up & TRAS Down and stated that the recent trend of RRAS shows quantum of RRAS Down being more than RRAS Up quantum.

15.3 **NTPC** suggested uniform market clearing price (UMCP) for both TRAS-Up and TRAS-Down by citing recent observation in the existing RRAS volume where TRAS volume is almost double that of TRAS-Up.

15.4 **CER IIT Kanpur** suggested that pay-as bid framework may be more economical and fair mechanism for TRAS-Up Service.

15.5 According to **SRPC**, availability of transmission corridor /grid conditions should be considered while finalizing the TRAS providers. SRPC further commented that capping for procurement price needs to be mentioned. In the absence of capping, TRAS may be uneconomical.

15.6 **TATA Power** also sought clarification on discovery of TRAS prices in case of corridor congestion.

15.7 **Shri Bhushan** commented that there is no mention anywhere about economic dispatch in the draft Regulation.

15.8 **MP Ensytems** proposed that regulations can identify a band for the commitment charges as well as the cap but the detailed procedures should allow for adjusting the commitment fee and the absolute number on an annual basis, considering the market dynamics that may play out.

15.9 Some stakeholders (**CESC, NTPC, POSOCO, IEX, Dhariwal Infra Ltd. P.K. Aggarwal**) expressed concern over different price mechanisms for TRAS up and TRAS Down.

15.10 **Greenko** commented that any deviation could cause grid security issues and system blackout; and, therefore, economics should take a back seat while procuring AS, which mostly is deployed during contingent events. It was suggested that the proviso for putting price cap on TRAS procurement may be deleted.

15.11 **Ekniti** suggested that price cap may be removed or kept equal to variable cost of electricity (production and transmission) only. The sustenance of private asset owners will depend largely on the leverage between TRAS-UP and TRAS-DOWN and on capacity utilization.

15.12 Some stakeholders (**Ekniti India Pvt Ltd., MP Ensystem**) suggested that additional premium may be provided over and above MCP of TRAS for ESS.

Analysis and Decision

15.13 Some stakeholders requested for the rationale behind differential approach on price discovery for TRAS-Up and TRAS-Down. Some others suggested to adopt pay-as-bid mechanism for both TRAS-Up and TRAS-Down. Some stakeholders also requested for clarification on the mechanism of price discovery in case of transmission congestion. Some stakeholders asked to remove the provision of price cap, while some others suggested to specify the price cap similar to the DSM price cap.

15.14 On the issue of Uniform Market Clearing Price (MCP) Mechanism for TRAS-Up, the Commission would like to reiterate the rationale that MCP helps to ensure that the market participants bid at their marginal price. Also, this pricing mechanism has already gained acceptance in the Indian Power Sector. As regards the pay-as-bid principle for TRAS-Down, marginal price maynot berelevant and as such to start with the Commission has decided to go ahead with this principle of price discovery for TRAS-Down.

15.15 As regards the pricing mechanism in case of transmission congestion, the Commission would like to emphasise that the responsibility of price discovery has been entrusted to the Nodal Agency, as centralizing 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. However, after considering the suggestions received from the stakeholders, the Commission has modified Clause (1) of Regulation 15, to include the scenario of market splitting in case of any transmission constraints on the same line as that of energy market. The Commission does not envisage transmission congestion in case of TRAS-Down and hence there is no change in this regard for price discovery on pay-as-bid principle.

15.16 Some stakeholders suggested to remove price cap, while others asked to retain the same on similar line with the cap for DSM price.It is clarified that the Regulation provides for an enabling provision of price cap and for interventionby the Commission should the occasion arise. This is considered necessary to balance the interests of consumers and grid security need.

16 Scheduling and Despatch of TRAS

Commission's Proposal

16.1 The provision relating to Scheduling and Despatch of TRAS was proposed as under in the Draft Regulations:

"***18. Scheduling and Despatch of TRAS***

(1) *Scheduling and despatch of TRAS shall be according to the provisions of the Grid Code.*

(2) *Information in respect of the TRAS-Up and TRAS-Down cleared for the Day Ahead Market and the Real Time Market shall be published on the website of the Nodal Agency, and shall be simultaneously communicated to the concerned power exchanges for onward communication to the selected TRAS providers.*

(3) *The schedule for TRAS shall become effective from the time block starting 15 minutes after issue of the despatch instruction by the Nodal Agency:*

Provided that 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.

(4) *The Nodal Agency shall deploy the cleared TRAS-Up as under:*

a. In case the actual requirement for deployment of TRAS-Up is equal to the total TRAS-Up cleared in the market, the Nodal Agency shall issue despatch instructions to all such TRAS-Up Providers.

b. In case the actual requirement for deployment of TRAS-Up is less than the total TRAS-Up cleared in the market, the Nodal Agency shall issue despatch instructions to the TRAS Providers in the following manner:

(i) In the event of the MCP-Energy-Up-DAM being equal to the MCP-Energy-Up-RTM, TRAS-Up shall be despatched on pro-rata basis;

(ii) In event of the MCP-Energy-Up-DAM and MCP-Energy-Up-RTM not being equal, TRAS-Up with lower MCP-Energy-Up shall be despatched first followed by the TRAS-Up with higher MCP-Energy-Up:

Provided that if the actual requirement of deployment of TRAS-Up is less than the cleared volume in the market with lower MCP-Energy-Up, TRAS-Up cleared in the said market shall be despatched on pro-rata basis:

Provided further that if the actual requirement of deployment of TRAS-Up is more than the cleared volume in the market with lower MCP-Energy-Up, TRAS-Up cleared in the market with lower MCP-Energy-Up shall be despatched in full and the TRAS-Up cleared in the market with higher MCP-Energy-Up shall be despatched on pro-rata basis."

Comments Received

16.2 **NPTC** commented that at the time of deployment, there could be some URS power available with the Section 62 generators, whose cost is less than the MCP of TRAS discovered in the DAM or RTM. Hence while preparing the stacking order for deployment of Ancillary Service Providers, the cost of URS power should also be factored in. In case of availability of cheaper URS power, they should be first dispatched before coming to the selected AS providers in the Market. This will result in least cost supply of Ancillary Services and would benefit all the stakeholders by lowering the cost of procurement of Ancillary Services.

16.3 **SRPC** sought clarification whether the Revision of TRAS schedule can be done.

16.4 **CER IIT Kanpur** suggested that the timeline needs to be fine-tuned to ensure that it is consistent with the deployment process mentioned elsewhere in the regulation. It was also proposed that the regulations should differentiate between reduction in SRAS/TRAS deployment Vs SRAS/TRAS Down.

Analysis and Decision

16.5 On the issue of deploying the cheaper resources, the Commission would like to reiterate that market-based procurement has to be based on pre-defined rules. One cannot subject the AS procured through market to uncertainty and dispatch it only after the system operator ascertains that no cheaper source is available under administrative mode. Even in the energy segment of the market, after DAM or RTM transactions are cleared, some cheaper power in Section 62 projects (cheaper than the MCP of DAM or RTM) might remain un-dispatched. But the market rules don't allow supersession of the market discovered transaction by the 'cheaper' power available in Section 62 projects. Rightly so, else the sanctity of market-based transactions would be put to question. The two sets of transactions have to be treated and honoured separately based on their contract terms. To optimise all resources and to ensure economic dispatch, the AS Regulations have already mandated the Nodal Agency to assess the likely availability of URS power before placing AS requirements in the market. Once market for AS is cleared, its dispatch shall be governed by the system requirement and not by any other commercial consideration. Accordingly, the Commission has decided to retain the provision as proposed in the Draft Regulations.

16.6 As regards the revision of schedule for TRAS, the Commission would like to clarify that there could be a situation when the TRAS is cleared in the market but is not dispatched because the system requirement might not warrant such dispatch. Elaborate provision has made to this extent in Regulation 18 and it has also been provided that the TRAS cleared in the market but not dispatched would be entitled to commitment charge.

17 <u>Payment for TRAS</u>

Commission's Proposal

17.1 The provision relating to Payment of TRAS was proposed as under in the Draft Regulations:

"**19.** ***Payment of TRAS***

(1) *TRAS-Up Provider shall receive 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 despatched by the Nodal Agency.*

(2) *TRAS-Up Provider shall receive commitment charges at the rate of ten percent of the MCP-Energy-Up-DAM or the MCP-Energy-Up-RTM, as the case may be, subject to the ceiling of 20 paise/kWh for the quantum of TRAS-Up cleared in the Day Ahead Market or the Real Time Market as the case may be,but not instructed to be despatched by the Nodal Agency.*

(3) *The TRAS-Down Provider shall pay back to the Deviation and Ancillary Service Pool Account at the rate of their Energy-Down bid in the Day Ahead Market or the Real Time Market, as the case may be, for the capacity instructed to be despatched by the Nodal Agency.*

Comments Received

17.2 **MSEDCL** suggested that as participation of Section 62 generators in SRAS/TRAS will provide additional income opportunity, the benefits accrued from SRAS/TRAS should be shared with the DISCOMs. According to MSEDCL, DISCOMs tied up with these generators bear the fixed cost liability even when the power is not scheduled. These generators are generally free from risk with assured fixed cost from DISCOMs.

17.3 **MPPMCL** suggested that TRAS-Up Provider shall receivefixed charges in addition to the MCP-Energy Up and the same should be adjusted to the original beneficiaries for the quantum of Un-Requisitioned Surplus scheduled under Regulation Up Service.

17.4 **MPPMCL** submitted that the commitment charges should be shared with original beneficiary in the ratio of 50:50 or as deemed fit by the Commission. This sharing mechanism will motivate original beneficiaries to forecast their demand more precisely and increase participation in the TRAS DAM/RTM.

17.5 **BYPL, Shree Sangeet Dave** requested to explain the basis of 10% and ceiling of 20 paise/kWh. Further, it was suggested that the capacity scheduled for SRAS and TRAS should be excluded for the purpose of DSM.

17.6 **Tata Power** suggested that the commitment charge of Rs. 0.20/ kWh is very low and appears to be based on thermal generating capacity already available. It was suggested that higher commitment charge would bring in the desired diversityand a fillip for AS markets. Tata Power also sought clarification whether there will be any penalty for the TRAS Up provider in case it is unable to deliver due to forced outage or other factors beyond its control.

17.7 **Tata Power** commented that for TRAS-Down, the generator may be allowed to retain at least 25% of the VC as per the extant practice, to incentivise them for offering their quantum for TRAS-Down services. Tata power sought clarification on adequate mechanism to adjust fixed cost liability of beneficiaries with such generating stations.

17.8 **Torrent Power** commented that the participant committing energy for contingency should be appropriately compensated for allocating part of URS power for Ancillary Services.

17.9 **PCKL** sought clarity on who is going to bear the commitment charges in case no dispatch signal is given to a quantum.

17.10 **Sterlite Power** submitted that commitment compensation structure should also be put in place for Secondary Reserves Ancillary Services (SRAS), and for TRAS Down, as proposed for Tertiary Reserves Ancillary Services (TRAS-Up)

17.11 **Wartsila** commented that recovery of fixed charges will be a key factor in determining whether a generating station/entity can commit to providing ancillary services. The proposed commitment charge with ceiling of 20 paise/kWh is very low and may be increased to attract emerging technologies like ESS.

17.12 **CESC, RPG** submitted that in order to keepthe system ancillary-service ready, the AS provider will incur a running cost for both up and down regulation readiness. Accordingly, the cap on commitment charge should be removed and such charges should be increased for large participation of the TRAS Providers.

17.13 **NLCIL** proposed that as the TRAS Provider would commit for providing TRAS-down scheduling, the commitment charges should also be given to TRAS Provider for the quantum of TRAS-Down cleared in the Market in a similar way as given for TRAS-up quantum.

17.14 **Greenko** suggested to increase the commitment charge (Mark up of Re 1/kWh) to sufficiently cover the cost of setting-up and operating the resource and provide reasonable return on investment. It was further suggested that liability towards commitment charges may be socialized from the DSM pool account. The other alternative is to pass on the cost to the specific entities responsible for causing the requisition of AS. In some countries, the system operator anticipates AS in advance, and factors in the commitment charges towards AS in their ARR / Rate Base.

17.15 According to **Renew Power**, commitment charges need to sufficiently cover the cost of setting-up and operating the resource and provide reasonable return on investment. Renew Power suggested changing the cap to 50% of MCP-Energy-Up-DAM or the MCP-Energy-Up-RTM subject to a ceiling of 200 paise/kWh.

17.16 **POSOCO** proposed to add additional clause for forced outage and transmission congestion events to bring clarity on commitment charges as follows:

> *19 A.1. In case of forced outage of a unit of a TRAS provider which has been cleared Day Ahead Market, the TRAS shall promptly inform the same to the Nodal Agency. If required, Nodal agency shall procure the corresponding TRAS quantum of power in Real Time Market. The TRAS provider shall receive all payments based on the reduced quantum of power. In case of forced outage of the complete plant, the generating station shall be excluded from TRAS on receipt of the outage information from the generating station and no payment shall be made to such generating*

stations.

Provided that no such provision shall be available for the TRAS providers which have been cleared in Real Time Market.

19 A.2 In the case of a TRAS provider is affected by bottleneck in evacuation of power or Grid Disturbance, in line with Regulation 6.5.16 and 6.5.17 of IEGC 2010, such TRAS providers shall be excluded from TRAS, and they shall only receive payment on account of commitment charges as per clause 19.2 of these regulations.

Analysis and Decision

17.17 Some Stakeholders requested for the rationale behind the cap (of 10% of MCP or 20 paise/kWh whichever is lower) for commitment charge. Some others commented that the proposed cap is too low and should be increased. Some stakeholders suggested commitment charges for TRAS down. Others suggested to specify modalities of sharing benefits with beneficiaries.

17.18 As regards the rationale behind the proposed cap, the Commission would like topoint out that a detailed justification was already provided in this regard in the Explanatory Memorandum to the Draft Regulations. The size of the ancillary market is likely to be very small – going by international experience, in the range of 2-3% of the peak demand. As such, it is unlikely that an AS Provider would expect to recover full fixed cost by participating in this market. Market based procurement of AS is being introduced for the first time in the country and the stakeholders have expressed concern over the likely increase in system cost. The Commission has sought to balance the competing demands for -keeping the cost under control and making sure the interest of the prospective participants is sustained.Expectations of recovery upto 10% of the fixed charge – which translates to 20 paise/kWh on the assumption of the fixed charge being in the range of Rs. 2/kWh on an average - are considered adequate. Hence, the Commission has decided to retain the proposed cap of 20 paise/kWh in the final Regulations. As regards the modalities of the sharing mechanism with beneficiaries, the Commission is of the view that same is outside the purview of these regulations.

17.19 In order to bring clarity on commitment charges in case of a forced outage of a unit or the entire generating station, the Commission has decided to accept the suggestion of POSOCO and added a new Clause in Regulation 19 of the final Regulations in this regard as follows:

"(4) In case of forced outage of a generating station or a unit of a TRAS Provider, being a generating station, which has been cleared in the Day Ahead AS Market, such TRAS Provider shall promptly inform the same to the Nodal Agency and the Nodal agency shall procure the corresponding TRAS quantum of power in Real Time AS Market, if required:

Provided that such TRAS Provider shall receive no payment in case of forced outage of a complete station; or receive payments based on the reduced quantum of power in case of forced outage of a unit, as the case may be."

Part III: Shortfall in Procurement of SRAS and TRAS or Emergency Conditions

18 <u>Regulation 20: Shortfall in Procurement of SRAS and TRAS or Emergency Conditions</u>

Commission's Proposal

18.1 The provisions regarding Shortfall in Procurement and Emergency Conditions were proposed as under:

"**20.** ***Shortfall in Procurement of SRAS and TRAS or Emergency Conditions***

In case of shortfall

(1) *All generating stations, whose tariff is determined by the Commission under Section 62 of the Act and having URS power after Gate Closure, shall be deemed to be available for use by the Nodal Agency for SRAS-Up or SRAS-Down or TRAS-Up or TRAS-Down, subject to technical constraints of such generating stations.*

(2) *The generating stations as referred to in clause (1) of this Regulation, whose URS is despatched as SRAS-Up shall be paid their variable charge in terms of clause (1) of Regulation 11 and incentive in terms of Regulation 12 of these regulations.*

(3) *The generating stations as referred to in clause (1) of this Regulation, whose URS is despatched as SRAS-Down shall pay back to the Deviation and Ancillary Service Pool Account in terms of clause (2) of Regulation 11 and shall be paid incentive in terms of Regulation 12 of these regulations.*

(4) *The generating stations as referred to in clause (1) of this Regulation, whose URS is despatched for TRAS-Up, in the event of short-fall in procurement of TRAS-Up through the Market, shall be paid at the rate of their variable charges for the quantum of TRAS-Up despatched.*

(5) *The generating stations as referred to in clause (1) of this Regulation, if despatched for TRAS-Down, shall pay back at the rate of their variable charges, corresponding to the quantum of TRAS-Down despatched.*

In case of emergency conditions

(6) *In case the Nodal Agency requires any generating station to provide Ancillary Services to meet the emergency conditions for reasons of grid security as per the provisions of the Grid Code, 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, or at the rate of the compensation charge declared by the AS provider, as the case may be."*

Comments Received

18.2 **NTPC** commented that there is no mechanism to take care of the risks of the Section 62 generators when the URS power isused for deployment. Hence a mark-up of 50 paise should be paid to such generators when their URS power is deployed to meet the Ancillary service requirements.

18.3 Some stakeholders **(Asit Singh, NHPC, PCKL, CESC Ltd. NTPC, APMuL)** commented that the generators participating in shortfall or emergency conditions should get additional premium like others**.**

18.4 Some stakeholders (**ERPC,Sterlite Power**) sought clarity on the provisions for refund of fixed charges to original beneficiaries in case of URS quantum is used in shortfall or emergency situation**.**

18.5 **WBSEDCL** requested that the state-embedded generating stations and pumped storage should be kept out of the purview of these regulations.

18.6 **Tata Power** sought clarification whether generating stations under Section 62 of the Act, in case of shortfall in procurement, will be allowed to declare self-determined variable charge different from that determined by the Commission. Tata Power also submitted that a suitable compensation mechanism/incentive scheme needs to be devised for TRAS-Down Providers being scheduled under the situation of shortfall, to take care of degradation in operating norms because of backing down. Clarification was also sought on the definition of emergency conditions.

18.7 **NTPC** suggested that the statement "and having URS power after Gate Closure" needs to be replaced with "and having URS power after RTM", as the availability of URS power may change depending on its participation and clearance in the Real Time Market.

18.8 **NLCIL** commented that after gate closure, actual URS capacity available with any generating station will vary based on clearance of generator's bid quantity in RTM. Hence, while doing SRAS-Up / TRAS-Up, final available URS power after implementation of RTM quantity in generator's schedule may be considered, subject to technical constraints of such generating stations.

18.9 **APMuL**submitted that generators governed by Section 63 of the Act who are willing to participate in the process should also be considered for meeting shortfall.

18.10 **CER-IIT Kanpur** suggested that the entities which respondto an emergency call need tobe incentivized.

18.11 **APMuL** proposed that for providing SRAS and TRAS during shortfall or emergency, compensation should be higher of MCP or variable charge to incentivize the service provider.

18.12 **CESC** sought clarification on whether generating stations whose tariffs are determined under section 62 or section 63 by the State Commissions are also eligible for providing support in case of emergency conditions. CESC submitted that emergency conditions may be appropriately defined.

18.13 **NLCIL** suggested that the incentive of 50 paise/unit may be paid to generating stations whose URS power would be used for TRAS-Up/ TRAS-Down scheduling during shortfall / emergency condition in the interest of grid security.

18.14 **BYPL** submitted that the emergency conditions should be specified in clear terms.

18.15 **NHPC** commented that as per the proposed Regulation, the nodal agency can utilize any generating station to provide ancillary services for reasons of grid security in case of emergencies and hence such generating stations should receive incentive as per Regulation 12(3) of these Regulations or provision of some incentives may be made separately for TRAS up and TRAS down in the case of shortfall.

Analysis and Decision

18.16 Some stakeholders suggested to include generating stations other than those whose tariff is determined under 62 of the Act. Some others commented that the generators participating in shortfall or emergency conditions should get additional premium while some stakeholders sought clarity on provisions for refund of fixed charges to original beneficiaries in case of URS quantum is used in shortfall or emergency situation.

18.17 The Commission would like to reiterate that grid security is paramount and cannot be left entirely to the mechanism of voluntary participation for SRAS or the market-based procurement for TRAS. Accordingly, with due regard to grid safety and security requirements, the Commission seeks to authorize the Nodal Agency to utilize, 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. However, the Commission has accepted the suggestions of the stakeholders to provide some incentive for such generating resources and accordingly have decided that such generating resources shall be paid@ 110% of their energy charges for the quantum of TRAS-Up in case of any deployment under shortfall conditions. Also, if such generating stations are deployed for TRAS-Down in shortfall conditions, they will pay back @ 90% of their energy charge to the pool account. However, the Commission has decided to retain the provision for SRAS Providers under short-fall condition, as proposed in the Draft Regulations, asprovision for incentive payment was already proposed for such Providers.

18.18 The Commission is of the view that under emergency conditions the Nodal Agency can instruct any generating station to provide Ancillary Service for the reason of grid security as stipulated in the Grid Code.

18.19 On the suggestion of stakeholders, the Commission has decided to replace the expression '*and having URS power after Gate Closure*' with '*having URS power after declaration of the RTM results'* in the Clause (1) of Regulation 20.

Part IV: Accounting and Settlement of SRAS and TRAS

19 <u>Regulation 21: Accounting and Settlement of SRAS and TRAS</u>

Commission's Proposal

19.1 Accounting and Settlement of SRAS and TRAS were proposed in Draft Regulations as under:

*"**21.Accounting and Settlement of SRAS and TRAS***

(1) *Accounting of SRAS shall be done by the Regional Power Committee on a*

weekly basis, based on SCADA data.

(2) *Accounting of TRAS shall be done by the Regional Power Committee on a weekly basis, based on interface meter data and schedules.*

(3) *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)

Provided that deviation from schedule by the AS Provider shall be settled first against the Ancillary Services schedule.

(4) *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.

(5) *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.

(6) *The net of the charges and the credits under clauses (4) and (5) of this Regulation shall be settled through the charges collected under the DSM Regulations.*

(7) *Settlement of payment liabilities in respect of the AS providers shall be done directly by the Nodal Agency on a weekly basis based on the accounts prepared by the Regional Power Committee.*

(8) *In case of deficit in the Deviation and Ancillary Service Pool Account for payment to SRAS Providers and TRAS Providers, surplus amount available in other Deviation and Ancillary Service Pool Account shall be used for such payment, as per the methodology stipulated in the Detailed Procedure.*

(9) *No retrospective settlement of variable charge or compensation charge, as the case may be, shall be undertaken.*

Comments Received

19.2 **POSOCO** commented that the payment to TRAS Provider should be made from the surplus available in respective regional DSM Pool account where the TRAS Provider is geographically located. TRAS/SRAS accounts of intra-state entities also need to be prepared by the respective RPCs. **POSOCO** also requested that the Regulations should clearly specify that no compensation would be provided to SRAS and TRAS Providers for part load or any other charges. According to **POSOCO**, the change in name for pool account would entail legal, procedural and taxation related issues and hence same may not be changed. **POSOCO** suggested that the guidelines for sequencing of payment for weekly accounting and settlement of TRAS may be specified in the Regulations.

19.3 On handling the deficit in Pool Account, **POSOCO** suggested the surplus available in Regional DSM pool account may be transferred to PSDF on quarterly/half yearly basis instead of monthly basis. Accordingly, PSDF Regulations may have to be amended. **POSOCO** also commented that three is no need to settle deviation against Ancillary first as the deviations are treated at the same rate irrespective of the type of transaction/schedule.

19.4 **BYPL** submitted that all payments should be received in or paid from the "Deviation and Ancillary Service Pool Account" which is nothing but the Regional Deviation Pool Account Fund referred to in the DSM Regulations.

19.5 **Tata Power** suggested that the States causing more deviation/dispatch of AS should be asked to pay for cost of AS, or the total cost of AS should be pro-rated among different participants as per their deviations. Tata Power also suggested that there should be a separate pool under the supervision of the Nodal Agency for AS, for transparency and clarity in collection/usage of funds.

19.6 **APMuL** sought clarification as to how the commercial accounting would be carried out if a generator is participating in SRAS, and also if it is part of primary response through RGMO.

19.7 **Sterlite Power** sought clarification as to whether the term 'SRAS MWh of AS Provider' in the formula refers to Scheduled or Actual MWh of SRAS service provided.

19.8 **NTPC** submitted that the provision of deviation from schedule to be settled first against the AS schedule is likely to result in a situation where any deviation from Schedule gets attributed to SRAS first. This can affect the performance evaluation drastically, particularly w.r.t. SRAS and hence the incentive payment also.

19.9 **SRPC** sought clarification on the proviso to Clause (3) of the Regulation 21 which providesthat deviation from schedule by AS provider shall be settled first against the Ancillary Service schedule.

19.10 **Shri Kumar** sought clarity on the equation in the referred regulation – while the term "Actual MWh of AS Provider" seems to suggest that it includes the total of actual energy, SRAS and TRAS by the provider, the necessity for explicit mentioning "including TRAS MWh" in the next term "Scheduled MWh of AS Provider including TRAS MWh" is not clear. Clarification was also sought on whether the third term "SRAS MWh of AS Provider" refers to actual or scheduled SRAS MWh.

19.11 **Shri Asit Singh** submitted that as generating station performance is being measured at generator terminal, SRAS MWh of generating station should be Actual Response (Mwh) x (1-NAC).

19.12 **Enel Green** sought clarification as to whether SRAS MWh is the quantum for which SRAS dispatch instruction has actually been received by the AS provider.

19.13 **CEEW** proposed that Regulations must take a forward-looking view and create an enabling framework for VRE generators to provide AS, especially as their share in the power system grows.

19.14 **Indi Grid Trust** sought review of provision for incentive and proposed that it should be based on actual basis.

19.15 **Enel Green** sought clarification as to whether DSM account for Ancillary would be the same as existing DSM pool Account.

19.16 **MB Power** submitted that Regulation 21(9) contemplates no retrospective revision of variable charges. However, it is not clear as to how will these Regulations then factor in retrospective tariff (including variable charges) revision required by law, like change in law adjustments, carrying cost, implementation of true-up orders and superior court judgements etc.

Analysis and Decision

19.17 Some stakeholders requested to reconsider the provision of settling deviation from schedule against the AS schedule first. Some others expressed concerns over change in the name of pool account citing legal, procedural and taxation related issues. Some stakeholders sought more clarity on the pool payment and contradiction between the SRAS (Up/Down) instruction and the sign change violation to manage deviation from their drawl schedule.

19.18 The Commission noted the suggestions of the stakeholders and decided to delete the provision stipulating settlement of deviation charges first with AS deviation. On the issue of change in the name from '*Regional Deviation Pool Account fund*' to '*Deviation and Ancillary Service Pool Account*' the Commission believes that there is no legal infirmity as suitable amendment to this effect has also been made in the DSM Regulations. On the sequence of payment to and from the pool account and clarity on the calculation of deviation of AS Provider, the Commission is of the view that the same would be governed as the DSM Regulations.

20 <u>Regulation 22: Transmission charges and losses for SRAS Provider and TRAS Provider</u>

Commission's Proposal

20.1 The provision relating to transmission charges and losses for SRAS and TRAS Provider was proposed as under in the Draft Regulations:

> *"**22. Transmission charges and losses for SRAS Provider and TRAS Provider***
>
> *No transmission charges or transmission losses or transmission deviation charges shall be payable for SRAS and TRAS"*

Comments Received

20.2 **IEX, Sterlite Power** sought clarity on applicability and treatment of transmission charges & losses for intra-state Service Providers.

20.3 **CESL** sought clarity on transmission charges or transmission losses, or transmission deviation charges payable for SRAS and TRAS. If there are any, the same needs to be captured in final Regulations.

- **PCKL** suggested that transmission charges and losses for SRAS Provider/TRAS Provider shall be payable from the Deviation Pool Account Fund referred to in the Regulations, or any such Account as may be stipulated by the Commission.

20.4 **TATA Power, APMuL** commented that waiver on transmission charges and losses would require amendment to the CERC (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2020. SRAS and TRAS Providers embedded in the state grid would be subject to intrastate transmission charges and losses. Suitable directions would be required to be issued to the Appropriate Commissions to provide such waivers. Islanded grids may also be examined in this context.

20.5 **MB Power** sought clarification as to how will the transmission charges and losses for SRAS and TRAS be computed.

20.6 **Sterlite Power** submitted that there is a possibility that some SRAS and TRAS providers could be connected to the intra-State transmission network, which would mean that they would be subject to intra-State transmission charges and losses. For this, suitable directions may be required to be issued to the different Regulatory Commissions so as to provide such waivers. Also, such waiver on transmission charges and losses may be made part of the CERC (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2020 by way of an appropriate amendment.

20.7 **Greenko** submitted that Energy Storage resources that provide SARS and TRAS services may have a schedule to inject energy to or withdraw energy from the grid and should be treated similar to generation resources providing SARS and TARS services. For this it should be clarified that storage resources should not be subjected to the transmission charges and losses. It was also suggested that storage resources should not be subjected to any additional fees if they submit schedules to withdraw energy from the grid for charging the storage resource.

20.8 **Shri Bhushan** also submitted that there is no mention about transmission constraints either, though all dispatch decisions have to be mindful of those.

20.9 Clarification was sought by **Shri Asit Singh** on transmission charges and losses of the state for an embedded utility in intra state system and participating in SRAS & TRAS.

Analysis and Decision

20.10 The Commission is of the view that Regulation 22 is sufficiently clear in that no transmission charges and losses would be applicable on SRAS Provider and TRAS Provider, as the same capacity would be deployed in the larger interest of grid safety and balancing of the system. As regards the clarification on similar provision for intra-State system in case such SRAS or TRAS Providers are embed in the intra-State system, the Commission would like to clarify that the same comes under the jurisdiction of the State Commission and hence is outside the purview of these regulations. However, the Commission may raise these issues at appropriate forum so that similar treatment may be specified for intra-State transmission system.

Part V: Miscellaneous

21 <u>Detailed Procedure</u>

Comments Received

21.1 **CESC** submitted that the Ancillary Service Regulations may be reviewed after "Detailed Procedure" are finalized as many provisions of the draft regulation are dependent on provisions of the Detailed Procedure. Stakeholders should be given achance to further provide their comments/suggestions in the light of information contained in the Detailed Procedure.

Analysis and Decision

21.2 The Commission is of the view that the Nodal Agency while formulating the Detailed Procedure shall consult the Stakeholders to provide further opportunity for comments on different provisions to be stipulated in the Detailed Procedure as per the guidelines specified in Regulations 23.

Sd/-	**Sd/-**	**Sd/-**	**Sd/-**
(P.K.Singh)	**(Arun Goyal)**	**(I. S. Jha)**	**(P.K. Pujari)**
Member	**Member**	**Member**	**Chairperson**

Annexure I – List of Stakeholders who submitted the written comments/suggestions/objections

1) Shree Sangeet Dave -Individual
2) Shree Bhanu Bhushan – Individual
3) IIT Roorki- Shree Arun Kumar
4) Shree Asit Singh- Individual
5) M/s Greenko Energy Pvt Ltd (GEPL)
6) M/s Mahavitaran (MSEDCL)
7) M/s Tata Power Company Ltd.
8) M/s Fluence-A Siemens and AES Company
9) Southern Regional Power Committee (SRPC)
10) M/s RP Sanjeev Goenka Group (RPG) Power Trading Company
11) M/s West Bengal State Electricity Distribution Company Ltd. (WBSEDCL)
12) M/s Convergence Energy Service Ltd. (CESL)
13) Indian Wind Power Association (IWPA)
14) Center for Study of Science, Technology and Policy (CSTEP)
15) M/s Wartsila
16) M/s NHPC Ltd.
17) M/s Ekniti India Pvt Ltd
18) M/s Karnataka Power Company of Karnataka Ltd. (PCKL)
19) Eastern Regional Power Committee (ERPC)
20) M/s PXIL Ltd
21) M/s NLC India Ltd
22) M/s ARBUTUS Consultants
23) M/s IEX Ltd
24) US – India Strategic Partnership Forum (US-ISPF)
25) M/s MP Ensystem Advisory Pvt Ltd.
26) M/s MB Power (Madhya Pradesh) Ltd.
27) M/s CESC
28) AEEE
29) M/s Dhariwal Infrastructure Ltd.
30) M/s NTPC
31) CEEW
32) M/s Tesla- India Motor
33) M/s Sterlite Power
34) M/s Radiance Renewable Pvt Ltd.
35) M/s Renew Power
36) M/s BYPL
37) M/s MP Power Management Company Ltd.
38) M/s NLC Tamil Nadu Power Ltd
39) M/s POWERGRID

40) Centre for Energy Regulation & Energy Analytic Lab- IIT Kanpur
41) Shree P.K. Aggarwal- Individual
42) M/s Enerl Green
43) Indi Grid Trust
44) M/s Torrent Power Ltd.
45) M/s AES India
46) India Energy Storage Alliance
47) M/s IRADe
48) Statekraft
49) APMuL
50) POSOCO

Annexure II – List of Stakeholders who presented their comments/suggestions/objections during Public Hearing

1) POSOCO
2) NTPC Ltd
3) Indian Energy Exchange Ltd. (IEX)
4) Power Exchange India Ltd. (PXIL)
5) NHPC Ltd
6) CER, IIT Kanpur
7) Customised Energy Solution Ltd.
8) M.P. Power Management Co. Ltd.