July 15th, 2021

Mr. Sanoj Kumar Jha,
Secretary
Central Electricity Regulatory Commission
New Delhi – 110001

Subject: Comments on "CERC Ancillary Service Regulations, 2021 (Draft)"

Dear Mr. Jha,

This is with reference to the "CERC Ancillary Service Regulations, 2021 (Draft)" issued by the CERC.

I have gone through it and record some of my comments on the same. Based on specific queries raised by the Committee members, additional suggestions are also provided for consideration. I would be pleased to provide additional inputs and clarification, if required.

Thanking you,

Yours sincerely,

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Comments on

"CERC Ancillary Service Regulations, 2021 (Draft)"

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1. **Design of Market for Ancillary Services:**
   Ancillary services have a very important role to play in secure operation of a power system. Increasing share of variable renewable energy sources, demand further attention of system operator. Reserves Regulation Ancillary Services (RRAS) has played a key role in bringing stability in system frequency. However, current design of ancillary services does not incentivise fast response ancillary services, which is critical in operation of ancillary services with high VRE share. Furthermore, RRAS, in its current form, is also restrictive in terms of eligibility for participation.
   The draft regulation is evaluated in terms of
   - Incentive for fast response ancillary services
   - Economically efficient and fair price discovery
   - Operationally efficient to implement
   - Pre-empts gaming

2. **Definitions of Demand Response (Regulation 3 (1j)):** The definition of demand response refers to the same being identified by the nodal agency as per the system requirement. This might be construed to mean that the nodal agency would identify demand response as one of the 'Supplier for ancillary services', whereas such specificity is not attached to other suppliers of ancillary services. Regulation should provide clarity with respect to the same.

   Further, 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.

3. **Define demand response aggregator:** A 'demand response aggregator' should also be defined, and its role be specified in the definition of demand response.

4. **Definition of Energy Storage (Regulation 3 (1n)):** The definition of Energy Storage may be modified as

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

The text in bold should be added to bring clarity to the definition. Insertion of 'other' would ensure presence of an intermediate technology to convert conversion electricity to the other form. In the absence of stored energy being injected back to the grid (after accounting for conversion losses), storage would only behave as a load.

5. **Definition and computation of URS (Regulation 3 (1ae)):** Unscheduled requisitioned surplus (URS) means the surplus capacity of a generating plant that has not been requisitioned by the beneficiaries, and is available for despatch. It should be computed as the difference between the declared capacity of the generating station and its total schedule by the respective beneficiaries. This should, thus, be calculated 'prior to scheduling and despatch of the respective ancillary services'.

6. **Eligibility for Demand Response an SRAS Provider (Regulation 7):** The eligibility for an SRAS provider, which especially mentions the eligibility for demand side resources, should enhance its ambit to include the 'demand response aggregators'. which could be embedded within Discom and may not be 'connected' to the intra-state transmission system. In such cases, appropriate metering and communication requirement under the eligibility conditions may need to be fine-tuned to enable 'aggregated suppliers' of ancillary services with multiple metering locations.

7. **Designing and Implementing a Demand Response Program:** In its true spirit, the demand response is a voluntary reduction in 'existing' demand of consumers, who have opted for the same. A reduction in 'demand' by load serving entities i.e. distribution licensees through load shedding should not qualify as demand response. To ensure effective participation of demand response, there is need to design and implement a demand response program with participation of aggregators, with adequate safeguards to ensure that the underlying rules encourage genuine demand response participation.

   A demand response aggregator can be included in the schedule of the respective SLDC as a virtual load/generator. The boundary for the demand response aggregator, covering identified loads (consumers), should have necessary metering and communication capability as defined in the eligibility conditions. The investment in such metering and communication capability can be justified under a business model for the demand response aggregator.

8. **Selection of SRAS Providers and Despatch of SRAS (Regulation 10(11)):** The average of SRAS-Up and SRAS-Down MW data shall be calculated for every 5 minutes time block in absolute terms for every SRAS Provider by the Nodal Agency using the archived SCADA data at the Nodal Agency. The **"**average of SRAS-Up and SRAS-Down" may be written as '5-min average of SRAS-Up and SRAS-Down' MW data to avoid the confusion.

9. **Selection of SRAS Providers and Despatch of SRAS (Regulation 10(12))**: The 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. The **"**average of SRAS-Up and SRAS-Down" may be written as '15-min average of SRAS-Up and SRAS-Down' MW data to avoid the confusion.

10. **Procurement of SRAS (Regulation 9(5)):** It is not clear whether the participating generator need to declare their variable charge in line with the charge determined under either section 62 or approved under section 63, or they have liberty to quote at variance. In case such generators are allowed to quote higher than their variable charges, this will increase the supernormal profit for the sub-marginal plants (as discussed later in these comments).

11. **Performance of SRAS Provider and Incentive (Regulation 12(2)**): Incentive should be provided based on actual response against the secondary control signal 'SRAS-Up/Down' sent every 4 seconds to the control centre of the SRAS provider. However, the measurement of performance on the basis of 5-minute MW data as calculated in Regulation 10 (Clause 11) is not clear and needs to be further elaborated.

12. **Performance of SRAS Provider and Incentive (Regulation 12(3)**): The IEGC mandates the system constituents to follow the system operator's instructions. The draft regulation provides incentive on the basis of **proportion of times an ancillary service provider responds to secondary control signal within the prescribed time limit.** This incentive would be applicable for the overall energy 'delivered' by the ancillary service provider across the day.

    The scale of proposed incentive in draft regulation seems to be disproportionately high and will impose ~~significant~~ undue burden, particularly on distribution utilities. It is important to note that generators are already provided incentives for (i) Ramping related incentive[1,] (ii) For Peak and off Peak Hours corresponding to scheduled generation in excess of ex-bus energy @ 65 paise/ kWh and @ 50 paise/ kWh, respectively[2]. Some of these existing incentives are themselves high and impose additional cost burden for the ultimate consumers, This issue has been highlighted earlier so in response to the relevant regulation/procedures[34].

    The proposed incentive going up to 40 paisa/kWh is disproportionately high and is not economically justified. An incentive of 10 paise/ **kWh** to the entities meeting just 20% cases of response to the SRAS signal does not seem to encourage even minimal efficiency in performance as enshrined in the Electricity Act 2003. The scale of incentives should be replaced with a scheme of penalty and incentive. The former should be applicable for deficient response to SRAS signal below 80%, and a

[1] POSOCO "Detailed Guidelines for Assessment of Ramping Capability" of Inter State Generating Stations (ISGS)" 2020. https://posoco.in/wp-content/uploads/2020/01/Ramp_Assessment_detailed-guidelines_6Jan2020.pdf

[2] CERC's Terms and Condition of Tariff Regulation, 2019 https://cercind.gov.in/2019/regulation/Tariff%20Regulations-2019.pdf

[3] Singh, A. *Power Chronicle*, Volume 3, Issue 4, April 2021, Newsletter of Energy Analytics Lab, IIT Kanpur. https://eal.iitk.ac.in/assets/docs/Power_Chronicle_Vol_03_Issue_04.pdf

[4] Singh, A. *Regulatory Insights*, Volume 3, Issue 4, April 2021, Centre for Energy Regulation (CER), IIT Kanpur. https://cer.iitk.ac.in/newsletters/regulatory_insights/Volume01_Issue04.pdf

minimal incentive of 10 paise/kWh for performance beyond that (upto 95 %) and 15 paise/kWh for 95% and above.

From point of view of total cost burden on ultimate consumers, incentive scheme should also be supplemented with penalty mechanism wherein performance below 45-70% band should be subjected to a penalty as suggested in Table 1.

Table 1: Incentive/ Penalty based on Performance

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
80 - 95 %	(+) 30	(+)10
70 – 80 %	(+) 20	0
50 – 70 %	(+) 10	(-5)
Below 50%	0	(-10)

13. **Procurement of TRAS (Regulation 16(2a)):** The draft regulation seems to suggest that a separate market segment would be created for TRAS for a Day-Ahead and Real-Time basis. It needs to be clarified that Day-Ahead and RTM market do not refer to the existing contracts being traded on Power Exchanges. To bring about this clarity, the proposed two market contracts may be called as DAM-TRAS and RTM-TRAS, respectively.

14. **Quantum of Requirement of SRAS and TRAS (Regulation 6 & 16(2a)):** Estimation of quantum of requirement for the SRAS or the TRAS close to the relevant time block as currently done in the case of RRAS would be a more meaningful exercise. In contrast, an estimation for TRAS on a day-ahead basis could not be undertaken reliably as system conditions are better understood close to the time block (especially due to variable renewable energy and demand variability) rather than on a day ahead basis. Furthermore, a day-ahead estimation of TRAS begins with a presumption of deviation greater than 100 MW. This is philosophically challenging as, under this regulation, the system operator is expected to 'estimate' possibility of such a deviation but not able to provide a framework to handle the same. This way, DAM-TRAS is proposed to work as a 'energy market' rather than ancillary services market as such.

    It is suggested that **a phased implementation strategy be adopted wherein RTM-TRAS is implemented along with SRAS in the first phase**. Introduction of DAM-TRAS would be relevant if the framework is not able to assure availability of the adequate resources at reasonable price as per the 'estimated' TRAS on RTM basis.

15. **Price Discovery of TRAS (Regulation 17**): The uniform market-clearing price for TRAS-Up on the basis of an 'estimated' requirement is economically inefficient and also exposes the mechanism to potential gaming. The market-clearing price would be decided by the marginal plant (participant) as per the 'estimated' quantum of TRAS-up (See Figure 1). This allows for significant supernatural profit to the sub-marginal plants (participants) (See Figure 1). This is also unfair to the beneficiaries (particularly the consumer serving distribution utilities), who have paid the fixed charges of the generating plants. Hence, there is no under recovery of fixed charges that needs compensation through a price over and above the variable charges.

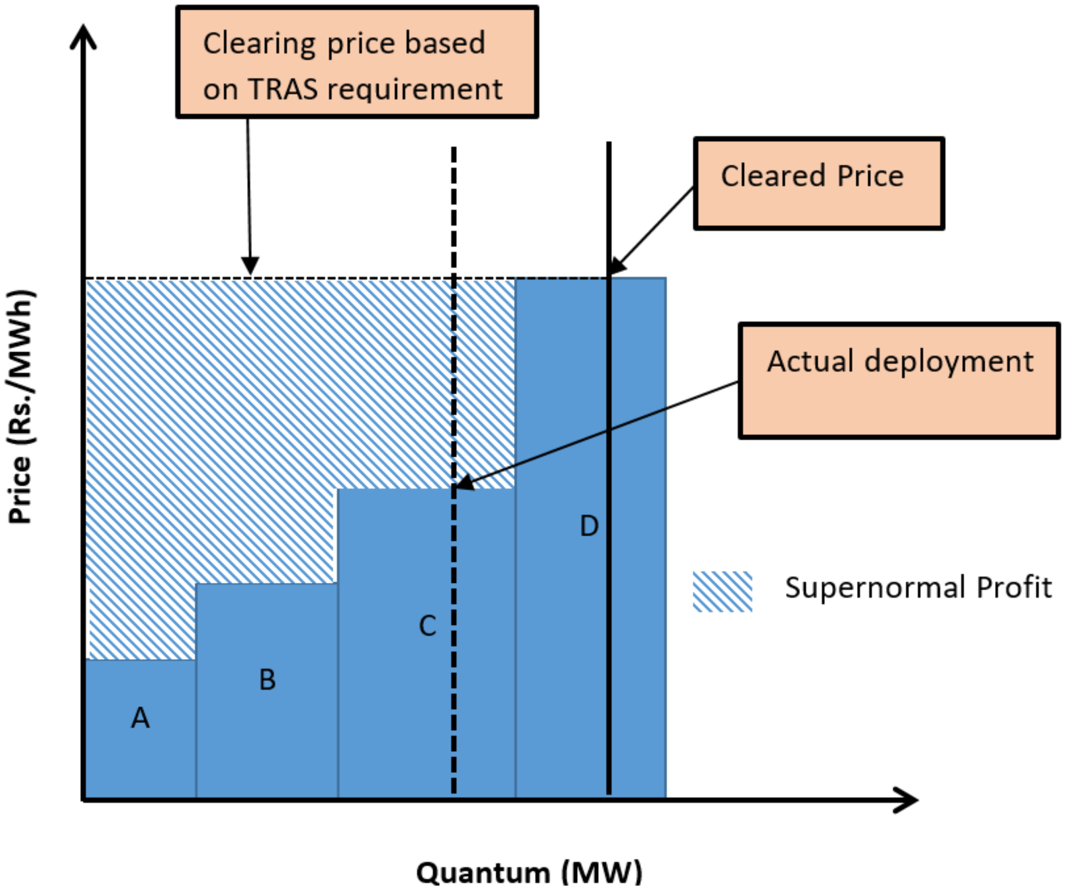

Fig. 1: Price discovery of TRAS-Up

Given that the existing generators will supply the TRAS-Up service from a capacity whose fixed charges are recovered under the prevailing tariff framework, any economic benefit that allows for recovery beyond the variable charges, and that too for a 'social good', would not be justified. Hence, **pay-as-bid framework would be economically more efficient and fair mechanism for price discovery of TRAS-Up service.**

16. **The Time-line for Scheduling and Despatch (Regulation 18(3)):** The draft regulation, while identifying timeline for activation of various ancillary services, does not seem to provide time required for data gathering from relevant telemetry, estimation of system parameters and decision making for activation, which may take few seconds to a minute. This would leave less than 15-minute of operational time for monitoring SRAS deployment and taking decision for subsequent SRAS/TRAS deployment. Accordingly, some of the suggested modifications include

18(3) - "continuous deployment for 15 minutes" may be replaced with 'immediately succeeding block' so as to provide operational clarity as shown in Figure 3.

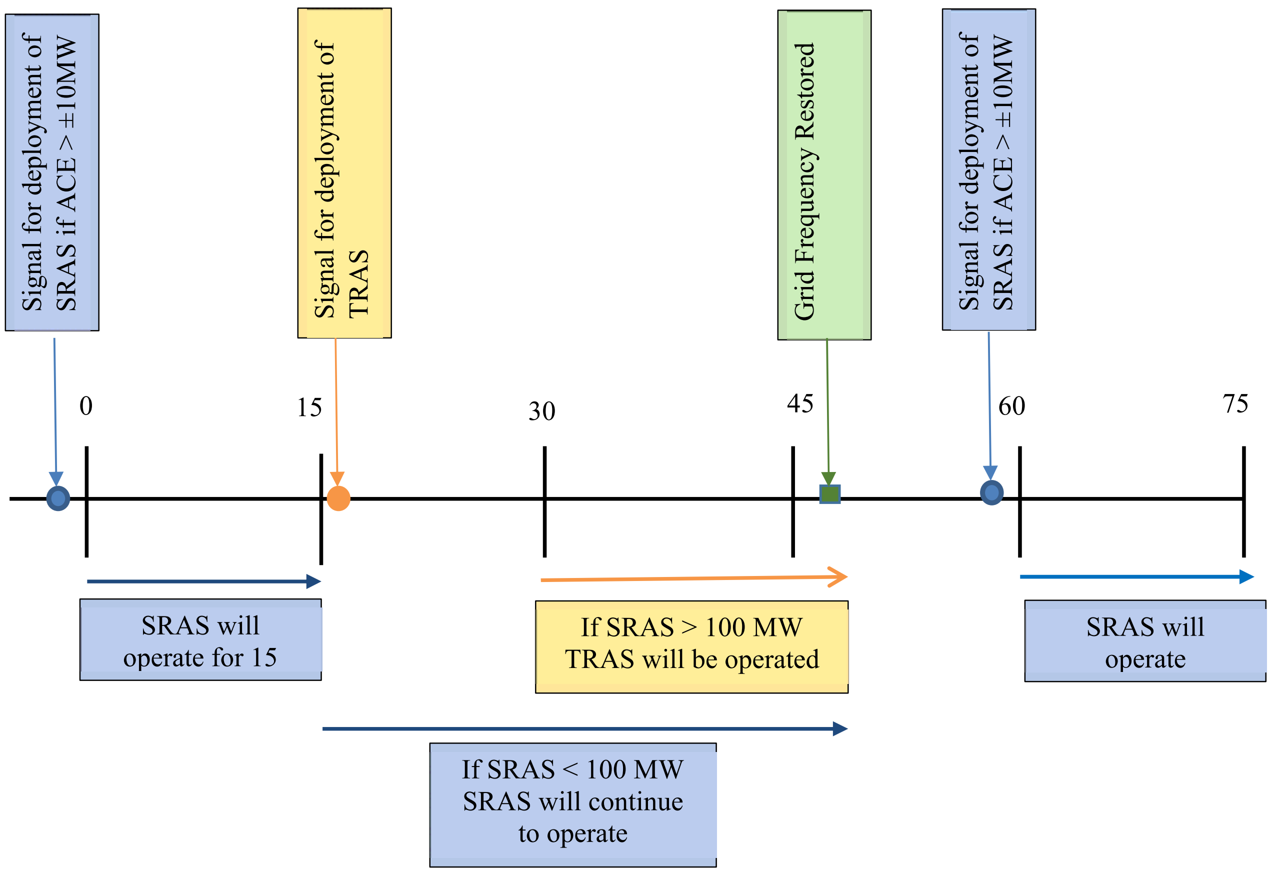

Fig. 2: Timeline for SRAS and TRAS operation

Fig. 1 of the explanatory memorandum suggests that the TRAS deployment can be done within the 15-minute deployment period of SRAS, to ensure the decision to activate and deploy TRAS is taken after the 15 minutes' operation of SRAS (above 100 MW in one direction), the SRAS would still need to operate for another period of 15 minutes till the TRAS takes over. Hence, **minimum operation time for SRAS, given the proposed condition in the draft regulation, would be 30 minutes. The timeline proposed in the draft regulation needs to be fine-tuned to ensure that it is consistent with the deployment process mentioned elsewhere in the regulation.**

17. **Differentiate between reduction in SRAS/TRAS Deployment Vs SRAS/TRAS Down:** Once SRAS/TRAS (Up/Down) is deployed, the system conditions may necessitate reassessment of the SRAS/ TRAS requirement. This should first be reflected in a reduction in the currently deployed Up (Down) service in the descending order of their variable charge/ MCP rather than a simultaneous deployment of Down (Up) service. Although the regulation's intent may be same, it should be clearly reflected in the regulation.

18. **Shortfall in Procurement of SRAS and TRAS or Emergency Condition (Regulation 20(1)):** For the purpose of calculating the incentives to be paid for RRAS Up/Down regulation under emergency/shortfall (Regulation 20(1)). The proposal for

incentive to respond to an emergency call would be much more justified than the one proposed in the Regulation 12(3).

19. **Proposed Methodology for Calculation of Allocation of Secondary Control Signal among SRAS-Up Providers: (Regulation 10(5)):** The process of evaluating the rate factor and cost factor does not provide adequate incentive to the eligible entities who can deploy the required ancillary services at a relatively faster rate, which are more relevant in the context of higher VRE share[5]**. We suggest modification to include ramping rate (in %) rather than in absolute term (MW/min) to provide correct incentive for the same.**

    The proposed approach to derive normalised rate participation factor and normalised custom participation factor uses the relative proportion of the rate factor or the cost factor, respectively, across the sum of those factors for all the market participants. The proposed methodology has distributional impact. The method of calculation of the normalized participation factor gives more weightage to plants with larger absolute rate factor, which would generally be associated with larger plants.

    Instead of using the rate factor based on absolute ramp rate, use of percentage ramp rate would provide a more robust estimation of the participation factor as explained through the following example.
    As per the allocation process proposed in the draft regulation, plant A gets proportionately higher allocation due to higher absolute value of the 'ramp rate', whereas plant C. get much lower allocation. Note that both the plants have same ramp rate in per cent but plant A has higher absolute rate. Calculations as per the suggested method herein, considering percentage ramping rate, provide adequate allocation to plant C as well.

[5] Das et al. (2020), Flexibility requirement for large-scale renewable energy integration in Indian power system: Technology, policy and modeling options, Energy Strategy Reviews, Volume 29.

Table 2: Methodology for calculation of Custom Participation Factor and Allocation of SRAS among SRAS-Up Providers (Draft Regulation)

SRAS Provider	Declared Capacity Pmax (MW)	Schedule (MW)	SRAS-Up Reserve (Range) (MW)	Rate Factor (MW/min)	Cost Factor (paise/kWh)	Normalized Rate Participation Factor	Normalized Cost Factor	Custom Participation Factor (CPF)	Normalised CPF(NCPF)	Ramp limited SRAS-Up Reserve	SRAS-Up Requirement (MW)	SRAS-UP Capacity with NCPF	SRAS Control Signal	Proposed CPF	Proposed NCP)	Proposed Redistribution of SARS Control	Proposed SRAS Control Signal
	(a)	(b)	(c) = [(a)-(b)]	(d)	(e)	(f) = [(d)/sum(d)]	(g) = [(e)/sum(e)]	(h) = [(f)/(g)]	(i) = [(h)/sum(h)]	(j) = Min [(c),(d)x15]	(k)	(l) = (i)x(k)	(m) = (l) subject to (j)	(h') = [(f)/(g)]	(i1) = [(h')/sum(h')]	(m1)	(m2) = (l)+(m1)
A	4150	4000	150	41.5	194	0.16	0.15	1.03	0.19	150	340	66	66	1.03	0.29	4.7	71
B	400	250	150	100	231	0.38	0.18	2.08	0.39	150		133	149	2.08	0.59	9.6	143
C	1050	950	100	10.5	264	0.04	0.21	0.19	0.04	100		12	12	0.19	0.05	0.9	13
D	1000	900	100	100	265	0.38	0.21	1.81	0.34	100		116	100	0.00	0.00	0.0	100
E	1320	1200	120	13.2	321	0.05	0.25	0.20	0.04	120		13	13	0.20	0.06	0.9	14

Table 3: Proposed methodology for calculation of Custom Participation Factor and Allocation of SRAS among SRAS-Up Providers

SRAS Provider	Declared Capacity Pmax (MW)	Schedule (MW)	SRAS-Up Reserve (Range) (MW)	Rate Factor (MW/min)	Proposed Rate Factor (%/min)	Cost Factor (paise/kWh)	Normalized Rate Participation Factor	Normalized Cost Factor	Custom Participation Factor (CPF)	Normalised CPF (NCPF)	Ramp limited SRAS-Up Reserve	SRAS-Up Requirement (MW) (assumed)	SRAS-UP Capacity with NCPF	SRAS Control Signal	Proposed CPF	Proposed NCPF	Proposed Redistribution of SARS Control Signal	Intermediate SRAS Control Signal	Final SRAS Control Signal
	(a)	(b)	(c) = [(a)-(b)]	(d)	(d1)	(e)	(f) = [(d1)/sum(d1)]	(g) = [(e)/sum(e)]	(h) = [(f)/(g)]	(i) = [(h)/sum(h)]	(j) = Min [(c),(d)x15]	(k)	(l) = (i)x(k)	(m) = (l) subject to (j)	(h') = [(f)/(g)]	(i1) = [(h')/sum(h')]	(m1)	(m2) = (l)+(m1)	(m3) = (l)+(m1)+(m2), subject to (j)
A	4150	4000	150	41.5	1.0	194	0.03	0.15	0.17	0.03	150	340	11	75	0.17	0.10	8.6	20	38
B	400	250	150	100	25.0	231	0.66	0.18	3.63	0.68	150		233	150	0.00	0.00	0.0	150	150
C	1050	950	100	10.5	1.0	264	0.03	0.21	0.13	0.02	100		8	8	0.13	0.08	6.3	14	28
D	1000	900	100	100	10.0	265	0.26	0.21	1.27	0.24	100		81	100	1.27	0.76	62.8	144	100
E	1320	1200	120	13.2	1.0	321	0.03	0.25	0.10	0.02	120		7	7	0.10	0.06	5.2	12	23