एनटीपीसी लिमिटेड
(भारत सरकार का उद्यम)

NTPC Limited
(A Govt. of India Enterprise)

केन्द्रीय कार्यालय/ Corporate Centre

Ref. No. 01/CD/ 701
Date: 18.10.2022

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

Sub: NTPC Submissions on Draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2022

Sir,

Hon'ble Commission vide its notification dated 7.6.22 has published the Draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2022 and has invited views/ comments/ suggestions/ objections from various stakeholders.

In this regard, please find enclosed Submission of NTPC on Draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2022.

Thanking you,

Yours Sincerely,

(Ajay Dua)
CGM (Commercial)

NTPC Submission on Draft IEGC

1. Regulation 43 provides that:

Control Area jurisdiction of system operator:

(4) The entities connected only to inter-state transmission system shall be under control area jurisdiction of Regional load despatch centre who shall be responsible for scheduling and despatch of electricity for such entity

(5) Entities connected to both inter-State transmission system and intra-State transmission system shall be under control area jurisdiction of RLDC, if more than 50% of quantum of connectivity is with ISTS, and if more than 50% of the quantum of connectivity is with intra-State transmission system, then it shall be under control area jurisdiction of SLDC.

Submission: It is submitted that in regards with Controlling Jurisdiction the existing IEGC provides that:

6.4.2 The following generating stations shall come under the respective Regional ISTS control area and hence the respective RLDC shall coordinate the scheduling of the following generating stations:
a) Central Generating Stations (excluding stations where full Share is allocated to host state),
b) Ultra-Mega power projects
(c) In other cases, the control area shall be decided on the following criteria:

i. If a generating station is connected only to the ISTS, RLDC shall coordinate the scheduling, except for Central Generating Stations where full Share is allocated to one State.
ii. If a generating station is connected only to the State transmission network, the SLDC shall coordinate scheduling, except for the case as at (a) above.
iii. If a generating station is connected both to ISTS and the State network, scheduling and other functions performed by the system operator of a control area will be done by SLDC, only if state has more than 50% Share of power.

6.4.3 There may be exceptions with respect to above provisions, for reasons of operational expediency, subject to approval of CERC.

i. It is submitted that as per the proposed Regulation if CGS has connectivity to STU for more than 50% and if 100% power is not allocated to state, scheduling shall be done by State LDC, presently in case of CGS it is being done by RLDC if 100% power in not allocated to the state.

ii. It is submitted that CGS is inherently regional in nature as 15% power is always at the disposal of the GoI and is allocated to different states time to time. However, since the definition of regional station provides that *'Regional Entity' means such entities which are in the RLDC control area and whose metering and energy accounting is done at the regional level*, after implementation of instant clause some CGS stations may not be considered as Regional Generating station and various clauses of IEGC and Regulations issued by Hon'ble Commission time to time for Regional Stations would not be applicable. It is therefore submitted that since as per act tariff of CGS is regulated by Hon'ble Commission, the provisions affecting the component of tariff such as compensation should also be governed by Regulations notified by Hon'ble Commission and not by state commission i.e. State Grid code. e.g. Regulation 45 (12) of Draft IEGC provides that:

Provided also that the <u>regional entity thermal generating stations shall be compensated</u> *for generation below the normative level either as per the mechanism in the Tariff Regulations or in terms of the contract entered by such generating station with the beneficiaries or buyers, as the case may be.*

Hence it will create a discrepancy in case of CGS stations whose tariff is determined by the CERC and compensation shall be payable as per CERC Regulations however the corresponding clause of IEGC for the entitlement of compensation shall not be applicable to such stations.

Similarly, Annexure 4 for Reactive Power Compensation provides that:

> *To discourage VAr drawals by <u>regional entities</u>, VAr exchanges with ISTS shall be priced as follows:*

It will also create a discrepancy when such CGS stations corresponding to the connectivity with the ISTS shall not be entitled to VAR compensation as they shall not be Regional Stations.

The DSM Regulation notified by Hon'ble Commission is also applicable to Regional Generating station.

Short title and commencement (1) These regulations may be called the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters) Regulations, 2022.

Scope: These regulations shall be applicable to all grid connected regional entities and other entities engaged in inter-State purchase and sale of electricity.

The Ancillary Services Regulations 2022 notified by Hon'ble Commission is also applicable to Regional Generating station.

Short title and commencement (1) These regulations may be called the Central Electricity Regulatory Commission (Ancillary Services) Regulations, 2022.

Scope (4): These regulations shall be applicable to all regional entities, including entities having energy storage resources and entities capable of providing demand response qualified to provide Ancillary Services and other entities as provided in these regulations.

iii. Therefore, it is submitted that as in respect of tariff related aspects CGS stations are under the preview of CERC, and since the Draft grid code proposes part load compensation to be claimed as per CERC Tariff Regulations therefore CGS stations should be under the control of RLDC.

iv. Further irrespective of quantum of connectivity, Central generating stations may be kept as regional entities and energy accounts continued to be issued by RPC for simplification of energy accounting and billing. It will be difficult for generator to refer accounts issued by different agencies which will lead to delays also.

v. It is submitted that since scheduling shall be done by SLDC such stations would face difficulties in scheduling of Ancillary / SCED due to lack of infrastructure/Communication link thereon with SLDC. Further many SLDC are also not WBES enabled.

Therefore, RLDC jurisdiction of CGS based on allocation of power may be retained.

vi. There may be a case when the connectivity is taken in equal proportion i.e. 50:50 with ISTS and Intra State Transmission system. Under these circumstances the controlling Jurisdiction may also be retained with concerned RLDC.

vii. The existing regulation 6.4.3 in regards with jurisdiction provides that:

for operational expediency, there can be exceptions to the above provisions subject to approval of Hon'ble Commission.

It is submitted that the existing clause 6.4.3 may also be retained.

Accordingly, the clause may be modified as:

Control Area jurisdiction of system operator:

The following generating stations shall come under the respective Regional ISTS control area and hence the respective RLDC shall coordinate the scheduling of the following generating stations:

a) Central Generating Stations (excluding stations where full Share is allocated to host state),

b) Ultra-Mega power projects

(c) In other cases, the control area shall be decided on the following criteria:

(1) The entities connected only to inter-state transmission system shall be under control area jurisdiction of Regional load despatch centre who shall be responsible for scheduling and despatch of electricity for such entity

(2) If entities are connected to both inter-State transmission system and intra-State transmission system, then such entities shall be under control area jurisdiction of SLDC if more than 50% of quantum of connectivity is with Intra-State transmission System, otherwise they shall be under control area jurisdiction of RLDC.

Provided there may be exceptions with respect to above provisions, for reasons of operational expediency, subject to approval of CERC.

2. Regulation 45(8)(a) Provides that:

The regional entity generating station shall declare ex-bus Declared Capacity, limited to 100% MCR, on day ahead basis as per provisions of Regulation 47 of these regulations.

Submission:

I. As per the proposed Regulation, the ex-bus Declared Capacity of generator will be limited to 100% MCR. In this regard, it is pertinent to mention excerpt of Statement of Reason (SOR) for IEGC 5th amendment regulations:

Quote

13.2.8: We are of the view that declaration of capacity including overload margins is the prerogative of the generator. *Generator based on its experience about the healthiness of the units is allowed to declare its declared* *capability based on machine and fuel/water availability. However, it was being observed that units which were scheduled beyond ex-bus capability corresponding to 100% of IC were not able to provide primary response as these units were operating on VWO mode leaving no margins for further valve opening by governor action during frequency decrease. As such, through the addition in Regulation 5.2 (h), of IEGC, RLDCs/SLDCs have been allowed not to schedule the units beyond ex-bus generation corresponding to 100% of installed capacity.* ***<u>However, for the purpose of calculation of PAF, DC declared by the generator is not to be reduced. This would ensure proper incentive for the generator for keeping units in readiness for providing much needed grid support in case of frequency excursion.</u>***

Unquote

As Hon'ble Commission has already dealt the matter in detail accordingly it is requested to continue the provision of restriction of schedule only upto 100% of normative ex-bus capacity and **the declaration of Declared Capability (DC) be the prerogative of the generator.**

II. It is worthwhile to mentioned that in respect of Margins required for primary response Regulation-47(2)(b) of the proposed draft regulation provides as follows:

Quote

"(b) Margins for primary response:

For the purpose of ensuring primary response, RLDCs and SLDCs, as the case may be, shall not schedule the generating station or unit(s) thereof beyond exbus generation corresponding to 100% of the Installed capacity of the generating station or unit(s) thereof. The generating station shall not resort to Valve Wide Open (VWO) operation of units, whether running on full load or part load, and shall ensure that there is margin available for providing governor action as primary response."

Unquote

The above provision itself suffices the purpose for keeping the reserve of 5% primary response in all machines (including the machines scheduled upto 100% of normative ex-bus), and it is similar to the provision made in IEGC 5th amendment Regulations. Hon'ble Commission may kindly take note of this and additional provision for restriction on DC upto 100% of MCR may be done away with.

III. Further following has been mentioned in the Explanatory Memorandum of the Draft grid code:

> *The declaration of DC has been proposed to be capped at 100% MCR considering that maximum schedule that can be given to such a generating station has been limited to 100%, considering mandatory margin to be kept for primary response under Regulation 47(2)(b) of draft Grid Code. It has been brought to the notice of the Commission that in some cases thermal generating stations have been declaring DC beyond 100% i.e. even for the capacity which cannot be scheduled under the 2010 Grid Code. The DC is an offer by generating stations to its buyers to schedule power. The DC against which schedule cannot be given is not appropriate. Accordingly, it has been stipulated that the DC shall be capped at 100%.*

In regards to above it is submitted that following has also been mentioned in the Explanatory Memorandum of the Draft grid code:

> *As per the present provisions for primary response, the Commission vide the fifth amendment of the 2010 Grid Code dated 12th April 2017 had restricted the scheduling of conventional generators to ex-bus generation corresponding to 100% of the Installed capacity of the generating station or unit(s) thereof, **so that the overload capacity as per Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007 can be utilized for primary control from thermal and hydro generators (non peak season)**. The same has been retained in the draft Grid Code [Regulation 30 (10) (h)].*

Hence the scheduling has been restricted to provide the Grid support and overload capacity of the machine is being used for serving the primary response.

Therefore, the availability of the machine is being used for scheduling and for providing the grid support as highlighted by Hon'ble Commission in Statement of Reason (SOR) for IEGC 5th amendment regulations

However, for the purpose of calculation of PAF, DC declared by the generator is not to be reduced. This would ensure proper incentive for the generator for keeping units in readiness for providing much needed grid support in case of frequency excursion.

i.e. the provision of declaration of capability (DC) based on machine and fuel/water availability was providing some relief to the generator to protect its commitment charges to keep its unit ready to respond when the grid demands.

The restriction on DC shall be an additional loss to the generator(s). As primary response is a part of Ancillary Services, either commitment charges should have been provided to generators or the declaration of capability (DC) should be kept as the prerogative of generator. As mentioned above there are various provisions in IEGC regarding the checks & balances of DC, and therefore, the additional restriction shall not serve any purpose but to demotivate the generator(s).

Restrictions imposed on scheduling by beneficiaries cannot take away the capability of the machine. It may be noted that schedules shall be finalized considering several factors such as availability of transmission corridors, Reserves for Primary Response, SCED etc. Whereas DC is the capability of the machine which is independent of all such factors and should not capped. Generator is supporting the grid with its capability and in fact such generators should be incentivized.

IV. It is also submitted that as per the draft Grid code Regulation 47(2)(b) provides that Hydro generating stations shall be permitted to schedule ex-bus generation corresponding to 110% of the installed capacity during high inflow periods to avoid spillage. Therefore, it is submitted that the maximum declared capacity for Hydro Stations may also not restricted.

Accordingly, the clause may be modified as:

"The regional entity generating station shall declare ex-bus Declared Capacity, on day ahead basis as per provisions of Regulation 47 of these regulations."

3. Regulation 47 (4) Revision of schedules on request of regional entities:

(a) SLDCs, regional entity generating stations, regional entity ESSs, beneficiaries, buyers or cross-border entities may revise their schedules under GNA as per clause (b) and clause (c) of this Regulation in accordance with their respective contracts.

(b) The request for revision of scheduled transaction for 'D' day, shall be allowed to be made in any time block starting 2 PM on 'D-1' day subject to the following:

(i) In respect of a generating stations whose tariff is determined under Section 62 of the Act, upward revision of schedule shall be allowed starting 2 PM on 'D-1' day, only in respect of the remaining available quantum of un requisitioned surplus after finalization of schedules under day ahead market.

(c) Based on the request for revision in schedule made as per sub-clauses (a) and (b) of Clause 4 of this Regulation, any revision in schedule made in odd time blocks shall become effective from 7th time block and any revision in schedule made in even time blocks shall become effective from 8th time block, counting the time block in which the request for revision has been received by the RLDCs to be the first one.

Submission: The exiting provisions of IEGC in this regard provides that:

Regulation 6.5 (18) Revision of declared capability by the ISGS(s) having two-part tariff with capacity charge and energy charge and requisition by beneficiary (ies) for the remaining period of the day shall also be permitted with advance notice. Any revision in schedule made in odd time blocks shall become effective from 7th time block and any revision in schedule made in even time blocks shall become effective from 8th time block, counting the time block in which the request for revision has been received by the RLDCs to be the first one.

Therefore, the existing regulation allows the ISGS generating units to revise their declared capability of the D day with advance notice.

DC revisions have been allowed only in certain cases of forced outages of the machines. In real time basis the Generating Stations may be required to revise their declared capability based on the various technical constraints which cannot be anticipated in advance while making declaration on D-1 basis and are beyond the reasonable control of Generator.

Operation of Thermal power plants involves running of several auxiliary systems handling various materials such as coal, ash, water etc. Some of these systems do not have in-built redundancy and sometimes equipments face breakdown due to various factors which are beyond the control of the generator, causing reduction in unit loading and requirement of downward revisions of DC. Subsequent to the normalcy of such equipments, upward revision of DC is required for restoring the load on machine.

Considering the technical difficulties, the Expert Committee Report has also permitted the DC revisions as follows:

***While making or revising its declaration of capability**, except in case of run-off-river (with up to three-hour pondage) hydro stations and canal fed hydro, the regional entity generating station shall ensure that the declared capability during peak hours is not less than that during other hours. However, exception to this rule shall be allowed in case of tripping/re-synchronization of units as a result of forced outage of units.*

(Emphasis added)

Therefore, the existing proviso of upward and downward DC revision in 7/8 time blocks may be retained.

4. Regulation 45 (15) provides that:

A generating station including renewable energy generating station shall be allowed to draw power from ISTS during non-generation hours, whether before COD or after COD, only after obtaining schedule for such drawal of power in accordance with a valid contract entered into by it with a seller or distribution licensee or through power exchange.

Submission:

i. It is respectfully submitted that in case of thermal generator unit tripping, due to process requirement there would always be requirement to run certain mandatory auxiliaries like Cooling water System, Turbine Lubricating oil system, Generator Seal Oil System, Air preheater, Station lighting, & Instrument air compressors. Stoppage of above auxiliaries may lead to equipment damage. Since unit tripping cannot be anticipated in advance which may be due to outage of transmission lines also, it is not feasible to wait to draw the such power by arranging through TGNA as the same shall be available only after 12th time block while the unit shall continue to draw the power from the grid to run mandatory auxiliaries. If standby supply is kept tied up for such drawal from state Discom it shall add to the operational cost. Therefore, it is submitted that the requirement of drawl of power by thermal generator during unit tripping considering as process requirement may be allowed under DSM and considering drawl under deemed TGNA.

ii. Similarly, thermal unit may be required to be start up immediately after tripping or may be required due to start up based on beneficiary requirement. Further duration and quantum of drawl of power in each time block during the light up process may vary significantly due to process requirement the arrangement of power through TGNA will increase the process time therefore the drawl of power for unit start up may also be permitted under deemed TGNA.

iii. It is worthwhile to mention that no such restriction was placed on thermal stations by Expert Group Report also.

iv. It is pertinent to mention that following provision has been provided under Regulation 19 (1) as per the existing methodology for interchange of infirm power for the commissioning of the new stations:

A unit of a generating station including that of a captive generating plant which has been granted connectivity to the inter-State Transmission System in accordance with GNA Regulations shall be allowed to inter-change infirm power with the grid during the commissioning period, including testing and full load testing before the COD, after obtaining prior permission of the concerned Regional Load Despatch Centre:

Provided that concerned Regional Load Despatch Centre while granting such permission shall keep the grid security in view.

v. Further Hon'ble Commission in Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters) Regulations, 2022 has pleased to mention that:

Quote:

(3) (a) The charges for deviation for injection of infirm power shall be zero.

(b) ***The charges for deviation for drawal of start-up power before COD of a generating unit or for drawal of power to run the auxiliaries during shut-down of a generating station shall be payable at the normal rate of charges for deviation.***

Unquote

Therefore, considering the fact that the duration and quantum of drawl of power in each time block for such types of drawl may vary significantly due to process requirement, and arranging through TGNA shall not serve the purpose as deviations shall continue to be there therefore drawl of start-up power before COD of a generating unit or for drawal of power to run the auxiliaries during shut-down of a generating station including REGS may be permitted under DSM.

5. Regulation 47(1)(b) provides that:

Entitlement of each beneficiary or buyer:

For generating station, where Central Government has allocated power, each State shall be entitled to a MW despatch up to the State's Share in the station's declared capacity for the day. Accordingly, based on declared capacity of such generating station, RLDC shall declare entitled share of each beneficiary or buyer for 0000 hours to 2400 hours of the 'D' day, by 7 AM on 'D-1' day

Submission: For some CGS stations which have completed useful life of 25 years, some beneficiaries have surrendered their entitlements either based on Regulation 17 of Tariff Regulations 2019 or based on Exit Policy of MoP. In such cases, beneficiaries who have not surrendered and are continuing with the allocations may get reduced entitlements in terms of MW since the same is calculated based on the States' share in the station's declared capacity. Since allocations of MoP are based on the Installed Capacity of the Station, it is therefore submitted that the entitlements should be calculated based on station's declared capacity for the day plus the quantum of untied/surrendered power. Accordingly, the following modification is proposed for 47 (1) (b) (i):

(i) Entitlement of each beneficiary or buyer:
For generating station, where Central Government has allocated power, each State shall be entitled to a MW despatch up to the State's Share in the station's declared capacity for the day. For CGS stations where there is un-tied/surrendered power, the entitlement of state continuing with the entitlements, shall be calculated based on the station's declared capacity for the day plus the quantum of untied/surrendered Power. Accordingly, based on declared capacity of such generating station, RLDC shall declare entitled share

of each beneficiary or buyer for 0000 hours to 2400 hours of the 'D' day, by 7 AM on 'D-1' day

6. Regulation 24 provides that:

DOCUMENTS AND TEST REPORTS PRIOR TO DECLARATION OF COMMERCIAL OPERATION

24 (1) Notwithstanding the requirements in other standards, codes and contracts, for ensuring grid security, the tests as specified in the following clauses shall be scheduled and carried out in coordination with NLDC and the concerned RLDC by the generating company or the transmission licensee, as the case may be, and relevant reports and other documents as specified shall be submitted to NLDC and the concerned RLDC before a certificate of successful trial run is issued to such generating company or the transmission licensee, as the case may be.

24 (2) Documents and Tests Required for Thermal (coal/lignite) Generating Stations:

(d) The generating company shall submit OEM documents for (i) performance characteristic curve for boiler, turbine and generator, (ii) starting time of unit in cold, warm and hot conditions, (iii) design ramp rate;

(e) The following tests shall be performed:

(i) Operation at a control load of fifty (50) percent of MCR as per the CEA Technical Standards for Construction for a sustained period of four (4) hours.

(ii) Ramp-up from fifty (50) percent of MCR to MCR at a ramp rate of at least one (1) percent of MCR per minute and sustained operation at MCR for one (1) hour.

(iii) Demonstrate overload capability with valve wide open as per the CEA Technical Standards for Construction and sustained operation at that level for at least five (5) minutes.

(iv) Ramp-down from MCR to fifty (50) percent of MCR at a ramp rate of at least one (1) percent of MCR per minute.

(v) Primary response through injecting a frequency test signal with a step change of ± 0.1 Hz at 60%, 75% and 100% load.

(vi) Reactive power capability as per the generator capability curve as provided by OEM considering over-excitation and under-excitation limiter settings.

Submission:

(i) As per draft IEGC 2022, Chapter-7, Scheduling and dispatch code, Regulation 45(12), *The minimum turndown level for operation in respect of a unit of a regional entity thermal generating station shall be 55% of MCR of the said unit.*

NTPC experience with the thermal fleet also confirms the same in view of flame stability and reliability for both supercritical and sub-critical Units. Accordingly, 55% of MCR may be considered as the lowest unit load at which the operational parameters can be maintained under auto control system. Testing for Operation of Control load at 55% of MCR for a sustained period of four (04) hours as per norms may be considered.

(ii) The units are provided with different number of coal mills depending upon the coal characteristics and the unit sizes. When the units load is to be increased, the coal flow through mill loading is increased accordingly. However, certain minimum loading of the mills is to be maintained to avoid any flame-out due to lean fuel air mixture.

The load variation by varying the mill loading can only be achieved within a certain range. Beyond this range one or more mills are to be cut in / cut out and during these transient periods, the parameters like temperature and pressure vary and certain stabilization period is required. The cutting in or out of milling system needs to be considered as integral part of ramp up or ramp down operation as continuous load ramp rate without mill cut in/out from technical minimum load i.e. 55% to full load (100% load) and vice versa is not feasible.

Hence 1% Ramp rate test needs to be carried out in steps with 02 nos stabilisation periods of 30 min each, from 55% to 100% of MCR and vice versa.

(iii) Projects where SG and TG are from different OEM's, design document certifying the designed Ramp rate is not available. In such cases, separate OEM documents for SG and TG shall be furnished and same may be accepted.

(iv) Turbine performance characteristic curve may please be elaborated. We understand it is Turbine start up curve.

(v) In regards with Reactive power capability, it is submitted that OEM Document indicating generator reactive power capability curve shall be submitted. Demonstration on the same shall be subject to prevailing voltage at grid interconnection point. Technically there may be a limitation based on grid voltage, GT impedance, AVR limiters etc.

7. Regulation 46(1) provides that:

SECURITY CONSTRAINED UNIT COMMITMENT (SCUC): The objective of Security Constrained Unit Commitment (SCUC) is to commit a generating station or unit thereof, for maximisation of reserves in the interest of grid security, without altering the entitlements and schedule of the buyers of the said generating station in the day ahead time horizon.

And
Regulation 46(4)(h) provides that:

UNIT SHUT DOWN (USD)

(i) The generating stations or units thereof, identified by NLDC in co-ordination with RLDCs, as per Clause (4) (c) of Regulation 46 of these regulations, but not brought on bar under SCUC, shall have the option to operate at a level below the minimum turn down level or to go under Unit Shut Down (USD). In case a generating station, or unit thereof, opts to go under unit shut down (USD), the generating company owning such generating station or unit thereof shall fulfil its obligation to supply electricity to its beneficiaries who had made requisition from the said generating station prior to it going under USD, by entering into a contract(s) covered under the Power Market Regulations.

Submission: Hon'ble Commission has introduced the concept of "Security Unit Commitment" with the objective of ensuring the Reserve in the system however in order to ensure units on bar having schedule less than technical minimum with the objective of economic operation and grid security is also required to be addressed.

In regards with scheduling, it is respectfully highlighted that many a times the units of the stations are getting schedule less than technical minimum. This leads to over injection by generators in many blocks causing DSM liability and grid instability. Therefore, following is submitted in this regard.

i. Beneficiaries gives requisition of power during peak hours and very less schedule during off peak hours leading to schedule generation (SG) less than Minimum turndown level in many blocks of the day **(Annexure I).**

ii. The generator has to request system operator / beneficiaries to provide schedule at least upto TM. Further it becomes quite difficult for generator to take decision of keeping the unit on bar or to go under Shutdown. The unit is kept on bar for these blocks by over injecting upto TM, with undesired deviations, incurring hefty commercial loss and grid instability.

iii. In case the generator decides for USD, shifting the commercial liability on the generators to fulfil the obligations by procuring the power from the market is unfair. As there would be schedule during peak hours, generators would have to buy at a high rate with no fault of generators.

iv. Non availability of unit during peak hours with demand remaining same shall increase the price of power during the peak hours which ultimately is increasing the power procurement cost.

v. It will also increase the cost of beneficiaries as unit will be under shutdown and they will also be forced to the buy the power from market if there is increase in their demand.

vi. If power is required by the beneficiaries during peak hours some mandate on the off-peak hours scheduling has to be there i.e. Beneficiaries must give Minimum percentage of schedule during non peak hour compare to schedule given during peak hours (this may be ensured by beneficiaries through Separate tariff for peak and off-peak period for consumers. This will help in flattening the load curve may address the issue of schedule below TM in non-peak hours.

vii. While mandating off peak hours scheduling it may be provided that beneficiaries must give minimum percentage of schedule during non-peak hours ensuring that the same are operationally reasonable and meeting the ratio between minimum and maximum generation levels of generators.

viii. In another option the gap between the actual schedule and tech minimum of the schedule may be met through SCED. This may require some change in SCED logic, i.e. the Schedule of some units may be reduced to increase the schedule of units which have less than TM schedule to meet the gap between actual schedule and TM schedule.

ix. Power to revise schedules

It is worthwhile to mention that considering the issue the Expert Group has provided **Power to revise schedules:**

RLDC may suo-motu revise the schedule of any regional entity generating station to operate at or above minimum turndown in the interest of reliable system operation. *While doing so, it is possible that the requisition of some beneficiaries may go up to ensure technical minimum. In this case, SLDCs may surrender power from some other inter-state generating station(s) or intra-state generating station(s) out of merit order. The concerned RLDC shall issue revised schedule accordingly and this shall be intimated to the concerned generating station, through the scheduling process.*

Hence it is submitted that the system operator should also be empowered to moderate the schedules inline with the draft Regulation 47(4)(d) whenever the schedule is below TM in certain blocks to ensure technical minimum schedule which is required for reliable system operation **as highlighted and provided by Expert Group in its Report**.

x. The units which have schedule less than technical minimum in certain number of blocks should also be considered for SCUC which will ensure units on bar with little efforts.

xi. The above measures will ensure Grid stability and reliability of the grid and shall help in providing rotating inertia which is required with increase RE integration in the system. This will also avoid the start up and shut down cost and shall lead to economic operation of the system.

In regards with USD it is submitted that the draft Regulations provide that Generating Stations will opt for USD when schedule is below the minimum turndown level after exercising available options to raise the schedule. In respect of USD, following issues need to be addressed:

i. DC declaration by generators on next Day (D+1)

ii. Scheduling of Generators on next day, off bar Units.

iii. If beneficiaries schedule above turn down level on next day, then also generators can't meet the schedule due to technical constraints of start-up time.

iv. Super critical units require at least 35-36 hours to come on bar, therefore they cannot meet the schedules till then.

v. After USD, advance visibility should be there with generator for bringing unit on bar.

vi. Generators should be compensated for start-up cost owing to USD due to less requisition by beneficiary.

Therefore, in reference to the obligation to supply, it is submitted that the generator must not be liable to supply power in case of USD which is due to unreasonable requisitions given by beneficiaries not meeting the minimum technical loading/requirements of generating units thus leading to Reserve Shutdown/Unit Shutdown of the units and also incurring extra operational expenses.

Instead generator is required to get compensated for extra operational expenses owing to USD. Detailed procedure for USD and then bringing of unit thereof with consideration of start-up time of Units and compensation mechanism need to be formulated in line with existing RSD procedure.

8. *Regulation 30(11) (t) provides that:*

All thermal and hydro generating stations make arrangements to enable automatic operation of plant from the appropriate load despatch Centre.

Submission: It is submitted that some of the units which are older than 20 years and units of capacity lower than 250 MW are equipped with Mechanical Hydraulic Governor without the provisions of CMC hence cannot respond to remote AGC signals. Accordingly, such units may be relaxed on technical grounds for automatic operation of plant from the appropriate load despatch Centre.

Accordingly, the clause may be modified as:

All thermal and hydro generating stations make arrangements to enable automatic operation of plant from the appropriate load despatch Centre.

Provided relaxation may be provided by appropriate load despatch Centre to units based on capacity or age on case-to-case basis.

9. Regulation 30 (9) provides that:

Primary Control:

(a) Primary control is local automatic control in a generating unit or energy storage system or demand side resource for the purpose of adjusting its active power output or consumption, as the case may be, in response to frequency excursion. Primary control is immediate automatic control implemented through turbine speed governors or frequency controllers.

(b) Primary control shall be provided by Primary Reserves Ancillary Service (PRAS).

(c) The minimum quantum of PRAS required for reference contingency shall be declared by NLDC at the start of each financial year.

(d) The generating stations & units thereof shall have the electronically controlled governing system or frequency controller in accordance with CEA Grid Connectivity Standards. Such generating stations and units thereof are mandated to provide PRAS.

(e) NLDC may also identify other resources such as ESS and demand resource to provide PRAS for which PRAS Providers shall be compensated in accordance with the AS Regulations.

Submission: It is respectfully submitted that as per the draft Grid Code generators have been mandated to provide the Primary frequency Response however to incentivize the generators for providing the grid support it is submitted that whenever the Primary Reserve Ancillary Services are introduced all PRAS providers including generators be compensated for providing the primary frequency response.

Accordingly, the clause may be modified as:

"(d) The generating stations & units thereof shall have the electronically controlled governing system or frequency controller in accordance with CEA Grid Connectivity Standards. Such generating stations and units thereof are mandated to provide PRAS and they shall be compensated in accordance with the AS Regulations."

10. The Regulation 21 (2) provides that:

In case the repeat trial run is to take place within twenty-four (24) hours of the failed trial run, fresh notice shall not be required.

Submission: At times it may happen that trial run is not successful and problem rectification may take time more than 24 hours. Therefore, the requirement of giving fresh notice may please be relaxed to 72 hours. i.e. if repeat trial run is taken within 72 Hours fresh notice shall not be required.

Accordingly, the clause may please be modified as:

"In case the repeat trial run is to take place within Seventy-Two (72) hours of the failed trial run, fresh notice shall not be required".

11. Regulation 45 (9) provides that:

Ramping Rate to be Declared for Scheduling:

i. Coal or lignite fired plants shall declare a ramp up or down rate of not less than 1% of ex-bus capacity corresponding to MCR on bar per minute.

ii. Gas power plants shall declare a ramp up or down rate of not less than 3% of ex-bus capacity corresponding to MCR on bar per minute.

iii. Hydro power plants shall declare a ramp up or down rate of not less than 10% of ex-bus capacity corresponding to MCR on bar per minute.

iv. Renewable Energy generating station shall declare a ramp up or down rate as per CEA Connectivity Standards.

Submission: It is respectfully submitted that though the Coal or lignite fired plants shall declare a ramp up or ramp down rate of 1.0% of ex-bus capacity corresponding to MCR on bar per minute. However, the system operator should consider the ramp rate declaration appropriately while revising the schedule of generator so that no DSM occurs to the Generator on account of ramp rate.

The present scheduling software of RLDCs is resulting in infeasible schedules which cannot be met by generating stations thus leading to DSM penalty on the stations. With the issuance of the DSM Regulations 2022, this penalty is likely to increase substantially. An illustration on this is given below:

If a 1000 MW station has a ramp rate of 1%/ minute, it can increase its generation by 15% (150 MW) in a block of 15 minutes. Accordingly, if the station has a schedule of 600 MW in a time block and is directed to ramp up, it can achieve a generation level of 750 MW at the end of the time block. Here the average generation in the ramping block will be 675 MW ((600+750)/2). However, the present scheduling software of POSOCO in such cases gives a schedule of 750 MW in the next block. Achieving an average of 750 MW in such block is not feasible. As the station achieves Average Generation of 675 MW, DSM penalty is imposed on the Generator.

Detailed Analysis of the impact is attached at **Annexure II.**

Further the Expert Group has provided that:

While finalizing the drawal and despatch schedules as above, the RLDC shall also check that the resulting power flows do not give rise to any transmission constraints. In case any constraints are foreseen, the RLDC shall moderate the schedules to the required extent, under intimation to the concerned regional entities. ***Any changes in the scheduled quantum of power which are too fast or involve unacceptably large steps, may be converted into suitable ramps by the RLDC.***

In view of above following proviso may be provided in above clause:

Provided the system operator shall consider the ramp rate declaration appropriately while revising the schedule of generator so that it does not lead to unacceptably large steps and no DSM liability occurs to the Generator on account of above.

12. Regulation 45 (12) provides that:

Minimum turndown level for thermal generating stations

The minimum turndown level for operation in respect of a unit of a regional entity thermal generating station shall be 55% of MCR of the said unit:

Provided that the Commission may fix through an order a different minimum turndown level of operation in respect of specific unit(s) of a regional entity thermal generating station:

Provided further that such generating station on its own option may declare a minimum turndown level below 55% of MCR:

Provided also that the regional entity thermal generating stations shall be compensated for generation below the normative level either as per the mechanism in the Tariff Regulations or in terms of the contract entered by such generating station with the beneficiaries or buyers, as the case may be.

Submission: It is submitted that the provisions regarding Part load compensations in the existing grid code may continue to be effective till part load compensations provisions are made applicable in tariff Regulations so that the generators continue to get the compensation.

Further it is requested that as draft grid code provides that the generating station on its own option may declare a minimum turndown level below 55% of MCR in this regard it is submitted that:

As per the POSOCO's report on "Flexibility Analysis of Thermal Generation for Renewable Integration in India", the average daily flexibility requirement of thermal generation has increased from 8-10% in 2009 to 15-18% in 2019 and is in the range of 15-17 GW. Further, the average daily flexibility requirement of the Indian power system is increasing at the rate of 5-7 GW per annum.

To meet this requirement, various interventions would be required to increase the flexibility of the existing thermal fleet which is designed for base load requirements. **The existing dispensation is such that the thermal generating station is compensated for the loss on account of degradation in station heat rate and auxiliary power consumption based on actual loss or normative whichever is lower. In many cases, the thermal generating station ends up making losses on account of cycling/flexing as the degradation is beyond normative norms.**

Further, there is no compensation for long-term costs towards deterioration due to accelerated aging, which may be challenging to assess accurately. It is one of the reasons that many thermal stations are reluctant to flex their generation to meet the grid requirements.

As the storage solutions are in the nascent stage and the cost is still unknown, it would be essential to promote flexibility for integrating large-scale renewables. It is therefore submitted that to carry out necessary modification/augmentation to make plants suitable for flexing, enabling provisions would be necessary not only to compensate for the cost but also to incentivize to take care of the long term impact on machine life due to thermal cycling.

Accordingly, the proviso may please be modified as:

Provided also that the regional entity thermal generating stations shall be compensated and incentivized for generation below the normative level either as per the mechanism in the Tariff Regulations or in terms of the contract entered by such generating station with the beneficiaries or buyers, as the case may be. However, the exiting provision of the Grid code 2010 in this regard shall continue to be effective till the same is made applicable in Tariff Regulation

13. ***Regulation 45(8)(b) provides that:***

The regional entity generating stations may be required to demonstrate the declared capacity of their generating stations as and when directed by the concerned RLDC. For this purpose, RLDC, in coordination with SLDC and the beneficiaries, shall schedule the regional entity generating station upto its declared capacity as declared on day ahead basis at time of first declaration.

RLDC shall ask each generating station, at least once in a year, to demonstrate the declared capacity.

The schedule issued by the RLDC shall be binding on the beneficiaries for such testing of declared capacity of the regional entity generating station.

In case the generating station fails to demonstrate the declared capacity, it shall be treated as mis-declaration for which charges shall be levied on the generating station by RPC as follows:

The charges for the first mis-declaration for a block or multiple blocks in a day shall be the charges corresponding to two days fixed charges at normative availability. For the second mis-declaration, the charges shall be corresponding to four days fixed charges at normative availability geometric progression over a period of a month.

Submission: The phrase "at the time of first declaration" may please be clarified. There may be reduction in DC due to genuine issues of some equipment tripping or due to change in coal quality. Hence demonstration of DC should take in account of such issues.

14. ***Enabling Clause for Flexibility Scheme:***

It is respectfully submitted that in order to promote bundling of cheaper Renewable Energy with costlier Thermal Power and to promote energy transition, MoP GoI vide dt. 12.4.22 has issued revised "Scheme for Flexibility in Generation and Scheduling of Thermal/ Hydro Power Stations through bundling with Renewable Energy and Storage Power".

The scheme inter alia provides that Generating Company can establish RE Plant as co-located or at new locations for replacement of costly thermal power and waiver of transmission charges shall be available.

Accordingly, in order to actualize the scheme, it is submitted that an enabling suitable provision may be provided. The indicative clause is as follows:

any thermal/hydro generating station operating under the flexibility scheme can replace the costlier power with the cheaper RE power by scheduling such RE power within the GNA quantum of thermal/hydro generator.

15. Regulation 47 (5) provides that:

(5) Grid disturbance of category GD-5:
(a) GD-5 is defined under Regulation 11(2) of CEA Grid Standards as "When forty per cent or more of the antecedent generation or load in a regional grid is lost".
(b) Certification of such grid disturbance and its duration shall be done by the RLDC.
(c) Scheduled generation of all the affected regional entity generating stations supplying power under bilateral transactions shall be deemed to have been revised to be equal to their actual generation for all the time blocks affected by the grid disturbance. Such regional entity generating station shall pay back the energy charges received by it for the scheduled generation revised as actual generation to the pool account.
Provided that, in case the beneficiaries or buyers of such regional entity generating station are also affected by such grid disturbance, the scheduled drawals of such beneficiaries or buyers shall be deemed to have been revised to corresponding actual generation schedule of regional entity generating stations.
Provided further that in case the beneficiaries or buyers of such regional entity generating station are not affected by such grid disturbance and they continue to draw power, the scheduled drawals of such beneficiaries or buyers shall not be revised.

Submission: It is submitted that on above matter following has been mentioned in the Explanatory Memorandum:

The Expert group has also suggested to consider cases of Grid Disturbance of category GD-5 only. <u>Accordingly, the draft Grid Code has proposed to consider only cases under GD-5 category.</u>

In this regard it may please be noted that on the above matter "The Expert group" has provided the following:

(11) ***In the event of*** *bottleneck in evacuation of power due to any constraint,* ***outage****, failure or limitation* ***in the transmission system****, associated switchyard and substations owned by the Central Transmission Utility or any other transmission licensee involved in inter-state transmission (as certified by the RLDC) necessitating reduction in generation,* ***the RLDC shall revise the schedules.***

(12) In case of any grid disturbance of category GD-5:

(a) scheduled generation of all the affected regional entity generating stations supplying power under long term / medium term/ short term transactions shall

be deemed to have been revised to be equal to their actual generation and scheduled drawals of the beneficiaries/buyers shall be deemed to have been revised to corresponding actual generation schedule of regional entity generating stations for all the time blocks affected by the grid disturbance. Certification of grid disturbance and its duration shall be done by the RLDC.

(b) The scheduled generation of all the affected regional entity generating stations supplying power under collective transactions shall be deemed to have been revised to be equal to their actual generation. Such regional entity generating stations shall refund the charges received towards such scheduled energy to the DSM pool.

(c) The declaration of disturbance shall be done by the concerned RLDC at the earliest. A notice to this effect shall be posted at its website by the RLDC of the region in which the disturbance occurred. Issue of the notice at RLDC web site shall be considered as declaration of the disturbance by RLDC. All regional entities shall take note of the disturbance and take appropriate action at their end.

(13) Energy and deviation settlement for the period of any grid disturbance causing disruption in injection and/or drawal of power shall be done by the RPC in consultation with RLDC and their decision shall by final.

Hence the Expert group has dealt with the matter holistically and only selected portion has been dealt in Draft Grid Code. NTPC submission in this regard is as follows:

The exiting provisions of IEGC in this regard provides that:

Regulation 6.5.17

In case of any grid disturbance, scheduled generation of all the ISGSs supplying power under long term/ Medium term shall be deemed to have been revised to be equal to their actual generation and the scheduled drawals of the beneficiaries/buyers shall be deemed to have been revised accordingly for all the time blocks affected by the grid disturbance. Certification of grid disturbance and its duration shall be done by the RLDC. The declaration of disturbance shall be done by the concerned RLDC at the earliest.

Hence in the existing Regulation in case of grid disturbance the generator schedule is made equal to actual generation, based on the certification issued by the RLDC. However, in the proposed draft the same has been provided only in case of GD 5 category and in all other cases generator has been left to suffer.

It is submitted that Generators suffers due to unit outage not only due to grid failure but due to tripping of outgoing lines also i.e. suffers loss due to fault not attributable to it. It is submitted that Hon'ble commission kindly look into, to avoid generator sufferance which occurs on account of:

i. DC Loss,
ii. DSM Loss,
iii. Start up Cost (Oil/Coal etc.)
iv. Incentive Losses (if applicable)

Therefore, it is submitted that in all cases of grid disturbances generator should be compensated based on the certification issued by concerned RLDC as exists in the existing provision of IEGC i.e.

In case of any grid disturbance, scheduled generation of all the ISGSs supplying power under long term/ Medium term shall be deemed to have been revised to be equal to their actual generation and the scheduled drawals of the beneficiaries/buyers shall be deemed to have been revised accordingly for all the time blocks affected by the grid disturbance. Certification of grid disturbance and its duration shall be done by the RLDC. The declaration of disturbance shall be done by the concerned RLDC at the earliest.

Further the declared capability (DC) of the generator should be protected for the period of grid failure (black-out)/tripping of any transmission line not attributable to the generator leading to unit(s)/station tripping and it shall be equal to the total DC (On bar+ Off bar) for the time-blocks preceding the period of grid failure till the units are put on bar. This will ensure that generator will not be deprived of DC due to grid failure.

It is also submitted that other losses (startup cost, incentive loss) may also be compensated to the generator in all cases of disturbance.

16. Chapter 1: Definitions

3(3) Regulation the definition of 'Ancillary Services' provides that:

Means in relation to power system (or grid) operation, the services necessary to support the power system (or grid) operation in maintaining power quality, reliability and security of the grid and includes secondary response, tertiary response, active power support for load following, reactive power support and black start;

Submission: Chapter 5 Regulation 30 (5) & (6) of draft Regulation provides that:

(5) The reserves shall be operated as Ancillary Services, namely (a) Primary Reserve Ancillary Service (PRAS); (b) Secondary Reserve Ancillary Service (SRAS); and (c) Tertiary Reserve Ancillary Service (TRAS).

(6) The mechanism of procurement and deployment of PRAS shall be as specified in these Regulations or in the Ancillary Services Regulations.

Therefore, providing the Primary Frequency Reserve may also be considered as Ancillary Service and may be mentioned in definition as and when introduced.

'Ancillary Services': Means in relation to power system (or grid) operation, the services necessary to support the power system (or grid) operation in maintaining power quality, reliability and security of the grid and includes Primary Response, secondary response, tertiary response, active power support for load following, reactive power support and black start.

17. ***3 (63) The definition of 'Hot Start' provides that:***

In relation to steam turbine, means start up after a shutdown period of less than 10 hours (turbine metal temperatures below approximately 80% of their full load values);

Submission: CEA Regulation of Construction of Power Plant provides the definition of Hot Start as follows:

for "Hot Start", in relation to steam turbine, means start up after a shutdown period of less than 10 hours (turbine metal temperatures approximately 80% of their full load values);

Therefore, the definition as provided in Draft grid code may please be aligned with CEA Regulation of Construction of Power Plant definition and may be changed as follows:

In relation to steam turbine, means start up after a shutdown period of less than 10 hours (turbine metal temperatures below approximately 80% of their full load values).

18. 3(1)(96) The definition of 'Regional Energy Account' or 'REA' provides that:

means accounts of energy and other parameters issued by the respective RPC for the purpose of billing and settlement of charges of ISGS and other users of the concerned region.

Submission: In order to facilitate the issuance of Regional Energy accounts by 2nd of every month the definition may be changed as:

Regional Energy Account' or 'REA' means accounts of energy endeavoured to be issued by 2nd of every month and accounts of other parameters issued by the respective RPC for the purpose of billing and settlement of charges of ISGS and other users of the concerned region.

19. Regulation 30(11) (j) provides that:

The SRAS Providers shall start responding to SRAS signals within thirty (30) seconds and shall be capable of providing the entire SRAS capacity obligation within fifteen (15) minutes and sustaining at least for the next thirty (30) minutes.

Submission: In coal-based units, command for change of generation goes instantly to the CMC system that in turn increases or decreases the coal feeding through boiler master. Actual load change is dependent on boiler response which is typically 2-3 minutes. Hence the proviso may be modified as following:

"The SRAS Providers shall start responding to SRAS signals instantaneously with load changes in 2-3 minutes and shall be capable of providing the entire SRAS capacity obligation at the rate of declared ramping rate and sustaining at least for the next thirty (30) minutes".

20. Chapter 3: Connection Code: Regulation 6(4) provides that:

After grant of connectivity and prior to the trial run for declaration of commercial operation, the tests as specified under this Code shall be performed.

Submission: It may please be noted that under the connection code no tests have been specified. Further in regards with tests, Regulation 24 provides as follows:

"DOCUMENTS AND TEST REPORTS PRIOR TO DECLARATION OF COMMERCIAL OPERATION"

Notwithstanding the requirements in other standards, codes and contracts, for ensuring grid security, the tests as specified in the following clauses shall be scheduled and carried out in coordination with NLDC and the concerned RLDC by the generating company or the transmission licensee, as the case may be, and relevant reports and other documents as specified shall be submitted to NLDC and the concerned RLDC before a certificate of successful trial run is issued to such generating company or the transmission licensee, as the case may be.

Therefore, the clause may please be aligned in line with provisions of Regulation 24 and following may please be provided:

After grant of connectivity and <u>before a certificate of successful trial run is issued,</u> the tests as specified under this Code shall be performed.

21. Regulation 21 provides that:

NOTICE OF TRIAL RUN

(1) The generating company proposing its generating station or a unit thereof for trial run or repeat of trial run shall give a notice of not less than seven (7) days to the concerned RLDC and the beneficiaries of the generating stations wherever identified. The concerned RLDC shall commence the trial run from the requested date or in case of any system constraints not later than seven (7) days from the proposed date of trial run. The trial run shall commence from the time and date as decided and informed by the concerned RLDC.

Submission: It is submitted that in case of RE generating station the power sale is normally to a single beneficiary and to avoid wastage of natural resource the requirement of giving 7 days' notice in case of RE generating stations may be reduced to 3 days' notice. Similarly in case of RE station the trial operation may be allowed to commence not later than 3 days. Accordingly, the clause may be changed as

21 NOTICE OF TRIAL RUN

(1) The generating company proposing its generating station or a unit thereof for trial run or repeat of trial run shall give a notice of not less than seven (7) days to the concerned

Provided in case of RE generating station trial run or repeat of trial run notice shall not be less than Three (3) days to the concerned RLDC and the beneficiaries of the generating stations wherever identified.

The concerned RLDC shall commence the trial run from the requested date or in case of any system constraints not later than seven (7) days from the proposed date of trial run. The trial run shall commence from the time and date as decided and informed by the concerned RLDC.

Provided in case of RE generating station, The concerned RLDC shall commence the trial run from the requested date or in case of any system constraints not later than Three (3) days from the proposed date of trial run. The trial run shall commence from the time and date as decided and informed by the concerned RLDC.

22. Regulation 22 (3) provides that:

Trial Run of Wind / Solar / Storage / Hybrid Generating Station

(a) Successful trial run of a solar inverter unit(s) aggregating to 50 MW and above shall mean flow of power and communication signal for not less than the period between sunrise to sunset in a single day with the requisite metering system, telemetry and protection system in service. The output of the generating station during the trial run shall be recorded and its performance shall be corroborated with the solar irradiation during the day and plant design parameters. Further, a declaration shall be given that no panel has been replaced or added or taken out and not altered the design of plant during period of the trial operation:

Provided that:

(i) the output below the corroborated performance level with the solar irradiation of the day shall call for repeat of the trial run.

(ii) If it is not possible to demonstrate the rated capacity of the plant due to insufficient solar irradiation, the same shall be demonstrated immediately when sufficient solar irradiation is available after the date of declaration of COD.

Submission:

i. It is pertinent to mention here that the capacity demonstration concept is primarily adopted in conventional generating sources with regulated tariff mechanism where power outputs are controllable & tariff is determined by regulatory commission and once project COD is done beneficiaries are liable to pay fixed charges. However, RE projects are developed based on TBCB concepts against a RFS defined by DISCOMS/REIA/any other entities. The conditions specified are different in many cases like minimum and max CUF, max and minimum energy deliverables & the penalties thereof etc. In case of other RTC tenders the concept of bidding is entirely different developers are left free to meet a particular output band with various types of resources and storage thereof. In order to meet these conditions, the capacities are planned with provisions of repowering options, storage capacity charge and discharge cycles depends on surplus energy scenarios etc. In view of above, since there is no fixed design considerations and developers adopt their own design and techno-economic considerations during life of plant to offer the best lowest competitive tariff, it is imperative to decontrol the capacity demonstration test of RE plants as in any case all the power from RE plants are any way scheduled and are through RLDCs. With this the developer need not divulge their propriety design considerations/strategies adopted in TBCB tenders. The capacity for which GNA sought by developer are any way based on their techno-economic considerations and injection of power shall be within these permissible limits and scheduling limits admissible. Further the commissioning of RE stations is being done based on the conditions mentioned in the PPA signed with the RE project developer i.e. based on the recommendations of the Commissioning Committee.

ii. Unlike thermal station, a SPV generating station is spread across hectares of land (for e.g. 300 MW SPV plant requires approximately 1500 acres). Due to such massiveness, variance in number of contributing attributes – insolation, ambient temperature, climatic conditions etc, may lead to dynamic and erratic nature of power output from the SPV generating station. Further, the latest CEA amendments demands the linking of inverter data to LDC on real time basis, which aids in assessing whether generating station/ inverters were in generating mode during the trial run.

iii. Capacity demonstration for wind and solar projects are not like thermal, where input is controllable. Here solar/wind resources are not controllable to developers. Wind project peak demonstrated in particular seasons and solar peak depends on radiation and ambient temperature combination, whereas trial run can happen at any time. There is no direct formula to link variable resources to controllable power output. As per prevailing charging procedures including data visualization and strict plant modelling are already being checked before trial run. Therefore, Entire plant is replicated to RLDC for FTC. So corroborating performance may lead to unwanted time and natural resources wastage as plant is ready to pump the cheap/must rum power immediately. Therefore, above dispute shall cause time delay and monetary loss to the Developers. It may please be noted that corroboration of performance level based on insolation, temperature may lead to dispute also because of various factors involved and different design considerations/optimisations techniques adopted by different developer based on RFS conditions floated by REIA/DISCOMS. Since each inverter data is shared with RLDC, corroborated performance can always be assessed in real time by RLDC. Therefore, it is requested to waive off the condition of trial run from sunrise to sunset for the full capacity and performance corroboration. The trial run may be conducted for a shorter span (limited to 4 hours) and declare successful trial run based on the generating mode of Inverter units and accordingly, the clause may be modified as:

(a) Successful trial run of a solar inverter unit(s) aggregating to 50 MW and above shall mean flow of power and communication signal for not less than 4 continuous hours between sunrise to sunset in any single day with the requisite metering system, telemetry and protection system in service

(b) Successful trial run of a wind turbine(s) aggregating to 50 MW and above shall mean flow of power and communication signal for a period of not less than four (4) hours during periods of wind availability with the requisite metering system, telemetry and protection system in service

(c) Successful trial run of a standalone Energy Storage System (ESS) shall mean one (1) cycle of charging and discharging of energy as per the design capabilities with the requisite metering, telemetry and protection system being in service.

(d) Successful trial run of a pumped storage plant shall mean one (1) cycle of turbogenerator and pumping motor mode as per the design capabilities upto the rated water drawing levels with the requisite metering, telemetry and protection system being in service.

(e) *Successful trial run of a hybrid system shall mean successful trial run of individual source of hybrid system in accordance with the applicable provisions of these regulations.*

It is also respectfully submitted that in general, the generating station/ inverter output is stepped up to 11/33 kV level where different inverters/ generating units are pooled. Further, it is integrated with EHV Grid through a Tie-Transformer. As per regulations, the entire connectivity link is designed based on (N-0) criteria. If due to tripping of inverter(s) or connectivity lines, that the output power during trail run declines, successful trial run may be accorded for the partial capacity, based on the generating unit/ inverter output data available at LDC. Hence, provision may also be provided for successful trial run for partial capacity out of the total intended capacity for trial run.

23. Regulation 25 provides that:

CERTIFICATE OF SUCCESSFUL TRIAL RUN

(1) In case of any concerns raised by the beneficiaries in writing to the concerned RLDC with a copy to the entity concerned regarding the trial run within two (2) days of completion of such trial run, the RLDC shall, within five (5) days of receipt of the such concerns, resolve as to whether the trial run was successful or there is a need for repeat trial run.

(2) After completion of successful trial run and receipt of documents and test reports as per Regulation 24 of these regulations, the concerned RLDC shall issue a certificate to that effect to the concerned generating station, ESS or transmission licensee, as the case may be, with a copy to their respective beneficiary(ies).

(3) **Submission:** It is submitted that no specific time limit has been provided for clearance of Trial Run, only when concerns are raised by beneficiaries the RLDC has to declare within 5 days of receipt of the such concerns that whether the trial run was successful or there is a need for repeat trial run.

A specific time limit should be provided for RLDC to declare whether the trial run was successful or there is a need for repeat trial run, as have been provided in exiting clause of IEGC 2010. The relevant IEGC clause provides that:

The concerned RLDC or SLDC, as the case may be, shall convey clearance to the generating company for declaration of COD within 7 days of receiving the generation data based on the trial run.

If the concerned RLDC or SLDC, as the case may be, notices any deficiencies in the trial run, it shall be communicated to the generating *company within seven (7) days of receiving the generation data based on the trial run.*

In view of above, the clause may please be modified as:

(1) In case of any concerns raised by the beneficiaries in writing to the concerned RLDC with a copy to the entity concerned regarding the trial run within two (2) days of completion of such trial run, the RLDC shall, within five (5) days of receipt of the such concerns, resolve as to whether the trial run was successful or there is a need for repeat trial run.

(2) <u>After completion of successful trial run and receipt of documents and test reports as per Regulation 24 of these regulations, the concerned RLDC shall convey clearance to the generating company for declaration of COD within 7 days of receiving the generation data based on the trial run.</u>

<u>If the concerned RLDC or SLDC, as the case may be, notices any deficiencies in the trial run, it shall be communicated to the generating company within seven (7) days of receiving the generation data based on the trial run.</u>

<u>In case of RE station the same shall be communicated within 3 days.</u>

24. Regulation 26 (4)(a) provides that:

The generating station based on wind and solar resources, the ESS and the hybrid generating station shall submit a certificate signed by the authorized signatory not below the rank of CMD or CEO or MD to the concerned RLDC and to the Member Secretary of the concerned RPC before declaration of COD, that the said generating station or the ESS as the case may be, including main plant equipment such as wind turbines or solar inverters or auxiliary systems, as the case may be, has complied with all relevant provisions of CEA Technical Standards for Connectivity, CEA Technical Standards for Communication and these regulations.

Submission: It is respectfully submitted that in case of RE generating Station the certificates as mentioned above may be allowed to be duly signed by the authorized representative /Head of Project of the concerned Renewable Plant on behalf of the generating company. Hence the clause may be modified as:

The generating station based on wind and solar resources, the ESS and the hybrid generating station shall submit a certificate signed by the <u>authorized signatory /Head of Project of the concerned Renewable Plant</u> to the concerned RLDC and to the Member Secretary of the concerned RPC before declaration of COD, that the said generating station or the ESS as the case may be, including main plant equipment such as wind turbines or solar inverters or *auxiliary systems, as the case may be, has complied with all relevant provisions of CEA Technical Standards for Connectivity, CEA Technical Standards for Communication and these regulations.*

25. Regulation 27(1)(c) provides that:

Provided also that in case a transmission system or an element thereof is prevented from regular service on or after the scheduled COD for reasons not attributable to the transmission licensee or its supplier or its contractors but is on account of the delay in commissioning of the concerned generating station or in commissioning of the upstream or downstream transmission system of other transmission licensee, the transmission licensee shall approach the Commission through an appropriate application for approval of the commercial operation date of such transmission system or an element thereof.

Submission: It is respectfully submitted that in case of transmission system a provision for commencement of commercial operation of the Transmission system has been provided when there is delay in commissioning of the concerned generating station or in commissioning of the upstream or downstream transmission system of other transmission licensee. However commensurate provision has not been provided for the CoD declaration of the generating station when its Associated Transmission system has not come and is not able to conduct the trial run. Therefore, a suitable provision may also be provided.

26. Regulation 27 (1) provides that
Generating Stations based on Wind and Solar resources; ESS and Hybrid Generating Station

The commercial operation date in case of units of a renewable generating station aggregating to 50 MW and above shall mean the date declared by the generating station after undergoing successful trial run as per clause (3) of Regulation 22 of these regulations, submission of declaration as per clause (4) of Regulation 26 of these regulations, and subject to fulfilment of other conditions, if any as per PPA.

(ii) In case of generating station as a whole, the commercial operation date of the last unit of the generating station shall be considered as the COD of the generating station.

Submission: It is respectfully submitted that in case of RE generating stations a suitable provision for declaration of CoD of remaining part capacity beyond 50 MW is required.

As per Central Electricity Authority Technical Standards for Connectivity to the Grid - Clause 14, for a Solar Photo voltaic (SPV) generating station, each inverter along with associated modules will be reckoned as a separate generating unit.

Therefore, after connectivity, Commissioning, and declaration of Commercial operation of first part Capacity (minimum 50 MW) subsequent capacity addition and declaration may be allowed as per invertor/unit size.

27. *Regulation 30 (10)(d) provides that:*

The generating stations and units thereof shall have the electronically controlled governing systems or frequency controllers in accordance with the CEA Technical Standards for Connectivity and are mandated to provide PRAS.

Submission: It is submitted that some of the units which are older than 20 years and units of capacity lower than 250 MW are equipped with Mechanical Hydraulic Governor. Accordingly, such units may be relaxed on technical grounds from providing the PRAS and clause may be modified as:

The generating stations and units thereof shall have the electronically controlled governing systems or frequency controllers in accordance with the CEA Technical Standards for Connectivity and are mandated to provide PRAS.

Provided relaxation may be provided by appropriate load despatch Centre to units based on capacity or age on case-to-case basis.

28. Regulation 30(10) Clause-(g) provides that:

Primary Control

g) The generating units shall have their governors or controllers in operation at all times with droop settings of 3-6 % or as specified in the CEA Technical Standards for Connectivity as per the requirements mentioned in the Table 4.

Fuel/ Source	**Minimum unit size/Capacity**	**Up to**
Wind/ Solar/Renewable Hybrid Energy Project* (commissioned after the date as specified in the CEA Technical Standards for Connectivity)**^**	Capacity of Generating station more than 10 MW and connected at 33 kV and above	10% of the maximum Alternating Current active power capacity in case of frequency deviations in excess of 0.3 Hz

***^**Wind/Solar/Hybrid plant commissioned after the date as specified in CEA Technical Standards for Connectivity shall have the option to provide primary response individually through BESS or through a common BESS installed at its pooling station.*

Submission:

i. Since the ISTS voltage level offered by CTU to RE generators is generally 220kV and above and RE capacity connected to ISTS at single location is normally of higher capacity i.e. of the order of 300MW or higher. Further the minimum size of RE capacity allowed for ISTS connectivity is also 50 MW. Therefore, the minimum size and voltage level may be revised to 50MW and 220kV.

ii. It may please be noted that the CEA technical standard was notified on Aug 2019, Various RE plants have been built with TBCB tenders since then. Provision for modification in tariff is not available to such plants as the PPA has already been signed, based on Tariff based Competitive bidding. Further, 10 % capacity to be met by BESS shall have financial implication to the Beneficiary which may be utilized under certain extreme grid situations and most of the time, such extra asset created will not be utilized.

    Therefore, for the reasons as mentioned above it is suggested to not to consider any BESS capacity for the plant which have been commissioned and under implementation based on tariff discovered through TBCB. However, if the same is made mandatory for the RE projects commissioned after August 19 the extra cost implication for providing the primary frequency response may please be allowed under change in law.

iii. It is pertinent to mention that Hon'ble Commission has already notified Ancillary services Regulation. In view of the above, after comprehensive study CEA/CTU may decide strategic location for installation of such grid security system common for whole Park like STATCOM, ESS as per grid requirement. This being specialized grid security ancillary services should be specified as a separate service maintained and operated by agencies specialized in this field. Such separate ancillary services, for which tariff may be determined separately through competitive bidding shall provide optimized overall cost to beneficiary considering RE plant tariff and PRAS service cost. This shall minimize the underutilization of such high costly BESS system if installed dedicated for the one solar plant.

iv. However, even if primary frequency response is to be mandated for RE plants then it may be considered for RE plants (having capacity 50MW and above) in line with conventional thermal generators and may be made mandatory prospectively.

Accordingly, the clause may be modified as:

g) The generating units shall have their governors or controllers in operation at all times with droop settings of 3-6 % or as specified in the CEA Technical Standards for Connectivity as per the requirements mentioned in the Table 4.

Fuel/ Source	Minimum unit size/Capacity	Up to
Wind/ Solar/Renewable Hybrid Energy Project^*	Capacity of Generating station more than 50 MW and connected at 220 kV and above	±5% of the maximum Alternating Current active power capacity. in case of frequency deviations in excess of 0.3 Hz

^Wind/Solar/Hybrid plant shall have the option to provide optional primary response individually through BESS or through a common BESS installed at its pooling station/ISTS Sustation.
** The RE stations shall be required to provide PRAS prospectively.*

29. *Regulation 30 (10)(h) provides that:*

All generating stations mentioned in Table-4 (under clause (g) of this Regulation) shall have the capability of instantaneously picking up to a minimum 105% of their operating level and up to 105% or 110% of their MCR, as the case maybe, when the frequency falls suddenly and shall provide primary response. Any generating station not complying with the above requirements shall be kept in operation (synchronized with the regional grid) only after obtaining the permission of the concerned RLDC.

Submission:

i. It may please be noted that the quantum of load jump should be as per generator droop. The exiting Grid code 2010 (first amendment to clause 5.2(f)(ii)(a)) in this regard provides that:

"For any fall in frequency, generation from the unit should increase as per generator droop upto a maximum of 5% of generation subject to ceiling limit of 105% of the MCR of the unit having regard to machine capability". **Therefore, the existing clause of grid code 2010 should be retained for better grid stability.**

ii. In regards with RE generating station this requirement of capability beyond 105% of their MCR may be met from BESS/ other Storage covered under separate for ancillary services to meet the primary frequency response. If generators are providing capacity beyond 105% beyond the MCR, it may be covered as optional Ancillary service.

Hence the clause may be modified as:

***h)** All generating stations mentioned in Table-4 (under clause (g) of this Regulation) shall have the capability of instantaneously picking up to* *a minimum 105% of their operating level and up to 105% or 110% of their MCR, as the case maybe, when the frequency falls suddenly and shall provide primary response. Any generating station supplying beyond 105% of MCR as per grid requirement shall be considered as Ancillary service.*

30. Regulation 30(10) (K) provides that:

The PRAS shall start immediately (within two seconds) when the frequency deviates beyond the dead band as specified in clause (i) of this Regulation and provide its full PRAS capacity obligation within 30 seconds and shall sustain up to five (5) minutes

Submission: The time required to achieve full PRAS capacity obligation is around 30 - 60 secs as per OEM of our machines. The load pickup response depends on mechanical system response including control valves. PRAS is delivered by the entrapped steam energy before the control valves of the turbine. Since the increase in load is not on account of increased coal firing, continued operation at increased capacity levels is not sustainable.

Further the Clause 5.2(h) of exiting IEGC provides that:

"after an increase in generation as above, a generating unit may ramp back to original level at a rate of 1%/min, in case continued operation at increased level is not sustainable".

In view of above it is submitted that clause may be modified as:

The PRAS shall start immediately (within two seconds) when the frequency deviates beyond the dead band as specified in clause (i) of this Regulation and provide its full PRAS capacity obligation within 60 seconds. After an increase in generation as above, a generating unit may ramp back to the original level at a rate of about one percent (1%) per minute in case continued operation at the increased level is not sustainable.

31. Regulation 30 (11)(u) provides that:

All renewable energy generating stations and ESS shall be enabled with frequency controller to provide Secondary control in accordance with CEA Connectivity standards and the communication system shall be established in accordance with CEA Communication Standards.

Submission: It is submitted that Secondary Control may not be mandated for RE plants as RE generation is not to be curtailed except for grid security concern. Therefore, Secondary Ancillary service may be taken from other SRAS providers through suitable mechanism. Accordingly, the clause may be modified as:

(u) Renewable energy generating stations and ESS willing to participate in SRAS Ancillary services shall be enabled with frequency controller to provide secondary control in accordance with the CEA Connectivity Standards and the communication system shall be established in accordance with the CEA Technical Standards for Communication.

32. Regulation 32 (3) (h) (i) provides that

In case of grid disturbances, system isolation, partial black-out in a State or any other event in the system that may have an adverse impact on the system security due to proposed outage,

(i)NLDC or RLDC, as the case may be, shall have the authority to defer the planned outage;

Submission: As per 2019-24 tariff regulations, capacity charges are recovered separately for High and Low demand seasons. Deferment of planned outages may affect adversely the recovery of fixed charges. Hence, there is need to protect the generator from such deferment which otherwise may get affected for its no fault. It is submitted that, such deferment should be considered as 100% deemed availability or actual availability achieved during the deferred period of the machine when the actual shutdown of machine is taken. Accordingly, the clause may be modified as:

In case of grid disturbances, system isolation, partial black-out in a State or any other event in the system that may have an adverse impact on the system security due to proposed outage,

(i)NLDC or RLDC, as the case may be, shall have the authority to defer the planned outage;

Provided on such deferment generator shall be entitled to deemed availability during the period of shut down corresponding to actual availability achieved during the deferred period.

33. Regulation 39(8) provides that:

Periodic or seasonal tap changing of inter-connecting transformers and generator transformers shall be carried out to optimize the voltages and if required other options such as tap staggering may be carried out in the network.

Submission: It is submitted that Generator transformers may be excluded from changing Taps periodically/ seasonally for voltage optimization. Hence following may please be provided

Periodic or seasonal tap changing of inter-connecting transformers and ~~generator transformers~~ shall be carried out to optimize the voltages and if required other options such as tap staggering may be carried out in the network.

34. Regulation 39(10) provides that:

Any commercial settlement for reactive power shall be governed as per regulatory framework specified as per Annexure–4 until the same is separately notified as part of CERC Ancillary Services Regulations.

Annexure 4 provides that:

1 (1) Reactive Power Compensation

To discourage VAr drawals by regional entities, VAr exchanges with ISTS shall be priced as follows:

I. The regional entity pays for VAr drawal when voltage is below 97%

II. The regional entity gets paid for VAr return when voltage is below 97%.

III. The regional entity gets paid for VAr drawal when voltage is above103%.

IV. The regional entity pays for VAr return when voltage is above 103%.

Where all voltage measurements are at the interface point with ISTS.

(2) The charge for VArh shall be at the rate of 5 paise/kVArh w.e.f. the date of effect of these regulations. This rate shall be escalated at 0.5paise/kVArh per year thereafter, unless otherwise revised.

Submission:

I. Elaborate mechanism for commercial settlement of Generators/IBRs exchanging of VARs with Grid may also be provided in Annexure-4 as provided for others.

II. Since generating station are located at distance from ISTS substation and connected through 220/400kV dedicated transmission Line. Voltage reference at local generating switchyard may be taken as reference for local reactive power compensation. It is also technically difficult for generator to measure the voltage at ISTS substation and take action at reactive compensation at Generator switchyard, it shall introduce time delay and error in voltage measured value and response which shall lead to voltage oscillation in the system. This may result into oscillation in active power also. Generator should be allowed to take reactive compensation action based on local voltage so that overall voltage stability of grid can be achieved.

III. The charge of VArh may be provided in line with existing rate of 10 paise/kVArh w.e.f. 1.4.2010, which is applicable between the Regional Entity, except Generating Stations, and the regional pool account for VAr interchanges. This shall provide the RE generators to optimize the reactive power management by actively participating in Reactive Power Ancillary services market through Inverter except peak active power generation hours. This rate of kVArh helps to compensate the extra maintenance cost of Inverter while participating in Reactive Power Ancillary Service market. This will encourages all RE generators to participate in the ancillary market which in turn shall offer RLDC more stable and flexible Grid.

IV. Further it may please be noted that Expert Committee Report provides that: *The charge for VArh shall be at the rate of 12.61 paise/kVArh and this will be applicable between the regional entity, except generating stations, and the regional pool account for Var interchanges. This rate shall be escalated at 0.6paise/kVArh per year thereafter, unless otherwise revised by the Commission.*

V. Therefore, the clause may please be modified as:

1 (1) Reactive Power Compensation

Reactive Power compensation should ideally be provided locally, by generating reactive power as close to the reactive power consumption as possible. The regional entities are therefore expected to provide local VAr compensation or generation such that they do not draw VARs from the EHV grid, particularly under low-voltage condition. To discourage Var drawals by regional entities, VAr exchanges with ISTS shall be priced as follows:

The regional entity pays for VAr drawal when voltage is below 97%

I.The regional entity gets paid for VAr return when voltage is below 97%.

II.The regional entity gets paid for VAr drawal when voltage is above103%.

III.The regional entity pays for VAr return when voltage is above 103%.

Where all voltage measurements are at the interface point with ISTS. For Generators, voltage measurement shall be at Generating Switchyard.

(2) The charge for VArh shall be at the rate of 10 paise/kVArh w.e.f. the date of effect of these regulations. This rate shall be escalated at 0.5paise/kVArh per year thereafter, unless otherwise revised by the Commission.

35. ***Annexure 4 provides that:***

All the Inverter Based Resources (IBRs) covering wind, solar and energy storage shall ensure that they have the necessary capability, as per CEA Connectivity Standards, all the time including non-operating hours and night hours for solar. The active power consumed by these devices for purpose of providing reactive power support, when operating under synchronous condenser/night-mode, shall not be charged under deviations and shall be treated as transmission losses in the ISTS.

Submission: voltage range beyond ±3% shall proposed for Ancillary volage support service. Therefore, CEA connectivity regulation voltage range to be revised and PF /Q control may be removed so that single control philosophy of voltage control mode can be followed so that developers can design system economically for TBCB tender and grid compliant.

Similarly, Developer may be encouraged to limit their reactive power injection/drawl from Grid by maintaining power factor near to unity. CEA Transmission planning criteria considers 0.98 pf under clause 16.4, the power factor band asked in CEA grid connectivity standard may be limited to pf of 0.98 instead of 0.95 which shall result into better grid reactive power management and also minimize the Reactive power Ancillary service to Grid. This also relieves RE developers from extra burden of reactive compensation arrangement which remain underutilized and if insisted would increase the RE tariff with nil or minimal utilisation. As an optimal measures such dynamic compensations if required need to be studied at suitable ISTS pooling stations and can be provided common for entire RE asset pooled at that point with net reactive power exchange requirements. With this the asset utilisation shall increase and beneficial to public at large. In some of the cases where some additional capacitor banks have been insisted there are already issue of voltage fluctuations/overvoltage situations. This need a wider consultation and deliberation among stake holders.
The voltage support at night/non-solar hours by solar plant is being optional to Developers it should covered under Voltage ancillary service, it should not be mandated in CEA Connectivity standard. Accordingly the Clause may be modified as:

3) All the Inverter Based Resources (IBRs) covering wind, solar and energy storage shall ensure that they have the necessary capability, as per revised CEA Connectivity Standards, all the time including non-operating hours and night hours for solar. The active power consumed by these devices <u>for purpose of providing optional reactive power support</u> under Voltage Ancillary service, when operating under synchronous condenser/night-mode, shall not be charged under deviations and shall be treated as transmission losses in the ISTS.

36. ***Regulation 39 provides that:***

REACTIVE POWER MANAGEMENT

(2) All generating stations shall be capable of supplying dynamically varying reactive power support so as to maintain power factor within the limits as per the CEA Connectivity Standard Regulations

Submission: The following is mandated in 'Manual for Transmission Planning criteria' for designing of Transmission system for the Renewable power plants;

"16.4 The wind and solar farms shall maintain a power factor of 0.98 (absorbing) at their grid inter-connection point for all dispatch scenarios by providing adequate reactive compensation and the same shall be assumed for system studies."

Since the above criteria is defined for all dispatch scenario considering all environment factor, grid stability and security it should be followed for grid compliance study and reactive power study for ongoing solar/wind plant. The relevant 'clause B2' of CEA regulation which provides that:

"B.B2.(1) The generating station shall be capable of supplying dynamically varying reactive power support so as to maintain power factor within the limits of 0.95 lagging to 0.95 leading." need further clarification and amendment.

Further it is submitted that, in the above clause of CEA regulation, the reactive power support capacity is not defined at rated MW capacity of solar plant. The requirements of solar plant are its capability to supply reactive power support @±0.95pf by combination of actual active and reactive power through PPC control. Since, the active power at POI is already defined at 0.98 pf under clause 16.4, CEA planning criteria, requirement of rated active power with 0.95 pf at POI should not be asked for in compliance to above clause B2.(1).

It is therefore, evident that most of the time the solar plant shall be connected to ISTS grid maintaining a power factor of 0.98 (absorbing) for maintaining Grid stability and reactive power balance in the grid. Depending upon Grid voltage, Solar Plant is mandated to provide reactive power support by enabling LVRT if voltage is less than 0.9 pu and through HVRT if voltage is above 1.1 pu. However, in normal condition i.e., 0.95pu to 1.05pu voltage, the reactive power available from solar plant after fulfilling active power as per P-Q capability at POI may be used for grid support.

Therefor it is submitted that CEA Grid Connectivity standard needs to be updated in line with Transmission Planning criteria. Accordingly, the clause may be modified as:

All generating stations shall be capable of supplying dynamically varying reactive power support so as to maintain power factor of 0.98 within the limits as per the CEA Connectivity Standard Regulations.

37. Regulation 40 provides that:

FIELD TESTING FOR MODEL VALIDATION

Power System Elements	***Tests***	***Applicability***
Non synchronous Generator (Solar/Wind)	*(1) Real and Reactive Power Capability for Generator* *(2) Power Plant Controller Function Test* *(3) Frequency Response Test* *(4) Fault Ride through Test (sample testing of a unit in the generating stations).*	*Applicable as per CEA (Technical Standards for Connectivity) Regulations, 2007*

Submission: The Fault Ride through Test of unit (WTG/Solar Inverter) at site (which are mostly remote for RE plants) requires specialised costly equipment and during testing it also likely create disturbances to the Grid it is connected. In the testing laboratory the simulators are available which can be easily used for Fault Ride through testing and permission from Grid is also available for such kind of testing facility. Therefore, the sample testing of unit may also be allowed in any Internationally acceptable/NABL accredited Testing lab where such kind facility is available. As this test is for one unit, Factory testing shall provide the same result as of site testing and developers shall be able to send the Unit Generators to site once it passes the test at factory. Hence the clause may please be modified as:

Power System Elements	***Tests***	***Applicability***
Non synchronous Generator (Solar/Wind)	***(1) Real and Reactive Power Capability for Generator*** ***(2) Power Plant Controller Function Test*** ***(3) Frequency Response Test*** ***(4) Fault Ride through Test <u>(sample testing of a unit at factory before commissioning).</u>***	***Applicable as per CEA (Technical Standards for Connectivity) Regulations, 2007***

38. Regulation 45 (14) provides that:

A generating station or ESS or a drawee entity shall be allowed to schedule injection or drawal only up to its effective GNA quantum or T-GNA quantum, as applicable, in accordance with the GNA Regulations.

Submission: It is respectfully submitted that as per the extant GNA Regulation the generator is allowed to inject upto the installed capacity without any transmission charges and only for purpose of drawl TGNA can be sought.

Further infirm power during commissioning of the unit or during trial operation is injected into the system only after taking the due permission from the grid operator within the stipulated period as provided for injection of infirm power in the extant Regulation and as also provided in this draft IEGC Regulation 19(1).

Therefore, the above clause may not be made applicable for exchange of infirm power and requirement of taking TGNA during infirm power exchange may please be dispensed with and exchange of infirm power may be allowed upto the permission granted by the grid operator after payment of transmission charges as applicable.

39. Regulation 47(1)(n)(v) provides that:

The NLDC shall announce the final schedule by 23.45 hrs of 'D-1' day and communicate to the RLDCs to prepare the schedule for despatch

Submission: It is submitted that to take care of unit parameter stabilisation during ramping up and ramping down, final dispatch schedule after finalization of RTM /SCED/AS should be available to the generator at least with two clear time blocks before the actual dispatch of generation.

Accordingly, the clause may please be modified as:

The NLDC shall announce the final schedule by 23.30 hrs of 'D-1' day and communicate to the RLDCs to prepare the schedule for despatch.

40. Annexure- 6 (ACCOUNTING AND POOL SETTLEMENT SYSTEM) Provides that:

(1)(a) At the Inter State Transmission System (ISTS) level, the basic principle followed is that all settlements for the energy scheduled are done directly between the sellers and the buyers, with the Regional Power Committee issuing the accounts specifying the quantum of energy scheduled. All deviations from the schedule are settled through a regulatory pool account maintained by RLDCs; a net settlement where only the deviation payments are handled.

Submission: It is submitted that the role of RPC in issuing various accounts may be clearly defined and accordingly following may please as provided:

RPC shall prepare monthly Regional Energy Account (REA), weekly unscheduled interchange account, reactive energy account, based on data processed by RLDC. RPC shall endeavour to provide monthly energy accounts at the earliest, in any case not later than 2nd day of succeeding month, to enable generators process energy bills in time.

Further the following may also be provided that:

The Energy accounting system shall be transparent, robust, scalable, and as far as feasible employ modern data processing tools and use standard reporting formats across different RPCs, compatible with standard ERP systems of generating utilities.

Annexure I

Drawl Scheduling Pattern of WR-I Beneficiaries from Solapur TPS

Drawl Scheduling Pattern of WR-I Beneficiaries from Solapur TPS									
Description	**GUVNL**	**MP**	**CG**	**MSEDCL**	**GOA**	**DNH-DD**	**OTHERS**	**TOTAL**	**Remarks**
Allocation (MW)	24	320	159	664	21	102	30	1320	2 X 660 MW
Technical Minimum @ 55 %	13	176	87	365	12	56	17	726	2 X 363 MW
Gross Injection Schedule during Off-Peak hour	13	0	0	365	12	56	0	446	With this schedule one unit can run and other unit has to be taken under RSD. Otherwise both units have to run well below technical minimum level.
Gross Injection Schedule during Peak hour	24	320	159	664	21	102	30	1320	Both units have to be kept i/s to cater this schedule.
Support being provided by GUVNL & MSEDCL during off-peak hour	25-100	0	0	365-450	12-15	56	0	455-620	With this schedule both units are being kept i/s.
Observation: During off-peak hour MP & Chhattisgarh are giving zero drawl schedule and during peak hour both are giving maximum drawl schedule. As a result, many a times both units of Solapur are being kept i/s with oil support during off-peak hour. In addition to this it is also being observed that, the beneficiaries who are providing support during off-peak hour are not getting the additional benefit during peak-hour. Therefore, it is suggested that the difference between the maximum and minimum drawl schedule in a day given by any beneficiary should not be more than 45 % of its (concerned beneficiary) maximum schedule.									

Annexure II

1.0 Analysis of DSM Loss due to Ramp Up/ Ramp Down

- Gross Deviation in DSM during 1% Ramping blocks for a typical station of 1000 MW (2 x 500 MW Units) is as follows.

Block	SG of Block	Scheduled Ramp	With 1% Ramp, generation achievable at the end of block	AG (Avg for the block)	DSM (MW)
1	1000	0	1000	1000	0
2	850	(-)150	850	925	75
3	700	(-)150	700	775	75
4	550	(-)150	550	625	75
5	700	(+)150	700	625	-75
6	850	(+)150	850	775	-75
7	1000	(+)150	1000	925	-75
8	1000	0	1000	1000	0

- Typically, all 1% ramping blocks will have inadvertent deviations in various station configurations, as follows:

Deviations in 1% ramping block	
Station	Deviations (MW)
840 MW (4 x 210 MW)	63 MW
1000 MW (2 x 500 MW)	75 MW
1320 MW (2 x 660 MW)	99 MW
1600 MW (2 x 800 MW)	120 MW

- Actual deviations in ramping blocks were analysed for some stations of WR region for FY'22 and losses calculated as per new DSM regulations considering actual MCP are as follows:

S No	Station	Installed Cap	No. of Blocks with 1% Ramp	Avg MW Deviation per Ramp block	DSM Loss due to Ramp (Lacs) @ actual MCP
1	Gadarwara	1600 (2x800)	1044	55.44	298.74
2	Khargone	1320 (2x660)	1522	33.21	156.34
3	Mouda STPS-I	1000 (2x500)	1629	45.68	383.94
4	Mouda STPS-II	1320 (2x660)	1632	43.64	321.16

5	Lara	1600 (2x800)	579	65.73	108.85
6	Solapur	1320 (2x660)	962	52.90	202.22

- It can be seen that based on the new DSM Regulations 2022, stations would have significant financial implications for reasons not attributable to them.