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Corporate Centre

Revision of the Indian Electricity Grid Code

Suggestions





Need for Revision of Grid Code

The next phase of the power sector will be characterized by:

- **Higher RE penetration and growth in RE capacity**
- **Evolution of power market**

The new regime will of Grid Operation will require the following:

- *Demand forecasting / RE forecasting*
- *Need for cycling by thermal generators,*
- *Increased Ramp up / ramp down requirements by conventional generators,*
- *Ancillary Services*
- *Need for further stabilising the Grid frequency .*
  - *Spinning reserves,*
  - *Secondary control reserves and AGC*

One Nation - One Grid Code

- The Regional Grids have been synchronously operating and India has a National Grid with Power Transfer to neighboring countries.
- For a National level power market, the Grid operation needs to be harmonized on a national level.
- For better Integration of RE, balancing has to be done at the National Grid level rather than at the State Grid level.
- State Grid Codes should be harmonized with the IEGC
- Preferably, there should be one Central Grid Code (IEGC) applicable for Grid Operation in the entire country.

Integration of RE

- RE power needs to be considered as “Must-run”, backing down of RE should be avoided
- Balancing of RE may be done on national basis and may be centrally controlled.
- Balancing resources may be pooled at national level; all the Gas, Hydro and Pumped storage plants, Grid scale battery storage may be considered for this purpose.
- Ramping up / Ramping down rate requirements may be met through appropriate price signal/ incentives may be introduced for managing this.
- Incentives may be introduced for supporting RE integration and trading in RE may be encouraged
- Incentives for low load operation of thermal plants

Move to Nominal Frequency of 50 Hz

- **Secondary Control:**
  - AGC needs to be introduced in more number of units so as to keep frequency within the governor dead band of target frequency of 50 Hz for >99% time and all machines can be operated on Governor control without much Governor hunting.
  - Appropriate allocation & Pricing mechanism for Spinning reserves for AGC.
- **Primary Control:** All machines, say above 100 MW, must operate on Governor control but not on RGMO.
  - Primary Up Reserve / Headroom need not be mandated at all stations (cheaper stations may be excluded, there by reducing the cost of power)
  - The Primary reserve required to keep Quasi SteadyState Frequency above 49.80 Hz (Estimate shows a freq decline of 0.15 Hz due to a contingency of 5000 MW Gen Loss) can be obtained from 60,000 MW capacity even during high RE scenario of 2021-22.
  - This can be obtained from moderately high ECR stations.
  - Ripple Factor may be set at ± 0.05 Hz till AGC is fully implemented.

Frequency range for equipment selection

- **Issue**
- As per present practice, power plant equipment including turbine are specified to be suitable for operation for a frequency range of -5% to +3%.

- **Suggestion**
- The same should be **+/-2%**.

Reactive power management

- Synchronous condenser may be added in planning code for voltage management

3.4 e) As voltage management plays an important role in inter-state transmission of energy, special attention shall be accorded, by CTU, for planning of capacitors, reactors, SVC and Flexible Alternating Current Transmission Systems (FACTS), <u>Synchronous condenser</u> etc. Similar exercise shall be done by STU for intra-State transmission system to optimize the utilisation of the integrated transmission network.

- Gas plants may be identified to be used as Synchronous Condenser
- Reactive power exchange through synchronous condenser may be considered as Ancillary service.

Demand forecasting

- As we intend to move towards a market based system, forecasting of demand has become critical for stable operation of the grid and stability of the market prices.
- IEGC should provide for forecasting of demand in different time horizons for all the states at the centralized level.
- Demand forecasting may be done by a central agency and this should be made available for all the stakeholders of the sector.
- Adequacy of contracts to meet the long term power requirement

Issues in RE Generation

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Issues	**Proposed Solution**
Treatment of Infirm Power	Infirm RE Power may be settled as Infirm **Thermal** Power. This should be applicable across States.
Drawal of power at night by Solar plants/ thermal plants under S/d / RSD	Presently there is no such provisions in Grid Code. Drawal may be permitted at DSM rate (once the tariff is fixed for life-time, input costs should remain same)
RE Stations are coming with State connectivity and subsequently transiting to RLDC requiring installation of new energy meters and rework on accounting of losses at Solar Parks	Grid Code may clearly define Quantum or voltage level above which RE stations to be at RLDCs

RSD and On Bar Scheduling :

- **Issue :**
- With More than 50% Entitlement available to one Beneficiary it is not Possible by many other states to call a large size unit On Bar from RSD even if there may be demand for same. Such problem is also being faced by Beneficiaries with small entitlements not good enough to support the technical minimum by its own.

- **Suggestion :**
- ***Option 2***: Scheduling may be permitted and if Unit is not available On Bar same may be scheduled under SCED by NLDC

Cold Start up time for Super-Critical units

- **Issue :**
- Current provision to call a unit in 8 Hrs from RSD is very uneconomic way of running the system as it is very difficult for large size units.

- **Suggestion :**
- Super-critical units brought on Bar from Cold start-up (800 MW) should be at least 35 hours.
- Further minimum 72 Hrs running requirement may also be defined for resource optimization.

Connectivity and Scheduling

- **Issues –**
  - Scheduling of CGS is done by RLDC except in case 100% power allocation is to the home state, where scheduling is done by SLDC.
  - Tanda Stage II is a CGS connected to State Network only and has power allocation to more than 1 state. As per Grid Code, responsibility of scheduling lies with RLDC.
  - However, for scheduling by RLDC and for drawing start-up power from ISTS connectivity to ISTS is required as per present Regulations.

- **Suggestion –**
  - In case of CGS connected to only STU, ***deemed connectivity*** to ISTS may be envisaged in Grid Code to facilitate scheduling by RLDC.
  - ISGS Switchyard may be considered as existing connectivity point to ISTS.

Technical Minimum for generators

- **Issue**
- Presently, ISGS have a technical minimum of 55% whereas technical minimum in case of State Generators varies from State to State. Therefore, while cheaper ISGS are backed down by the SLDC and less efficient state generators are not backed down as they have higher technical minimum. This increases the power purchase cost of the Discoms.

- **Suggestion**
- Uniform technical minimum needs to be specified irrespective of ownership.
- Stations like at Kudgi/Solapur/Mouda/Vallur and even Simhadri are forced to run at 55% of loading at times. Some mandatory critical routine operations like LRSB and some contractual obligation like PG test needs the machines to run at higher loading than 55%. So RLDC must be empowered or there shall be provision in scheduling mechanism to take care of the above requirements time to time.

Ramping up / Down Rate

- As Commercial implications has been introduced by Tariff Regulations, 2019; IEGC may be suitably amended for ramping rates and as to how ramp rate needs to be demonstrated.

- Staircase method providing generating station sufficient timeline to achieve required ramp rate by taking additional equipment’s like Mills, etc., may be factored.

- Ramp rate should be taken into account while finalizing the schedule of a station, including sale of URS power in PX

Scheduling provisions for defaulting utilities

- Consent of Generators may be taken to allow rescheduling of URS power to defaulting DISCOMs.
- Regulated entities should not be allowed STOA for replacement power in case of generator payment default (similar to Transmission payment default)
- Automatic Regulations of power supply after a specified period of Default in payments

RRAS and SCED scheduling mechanism

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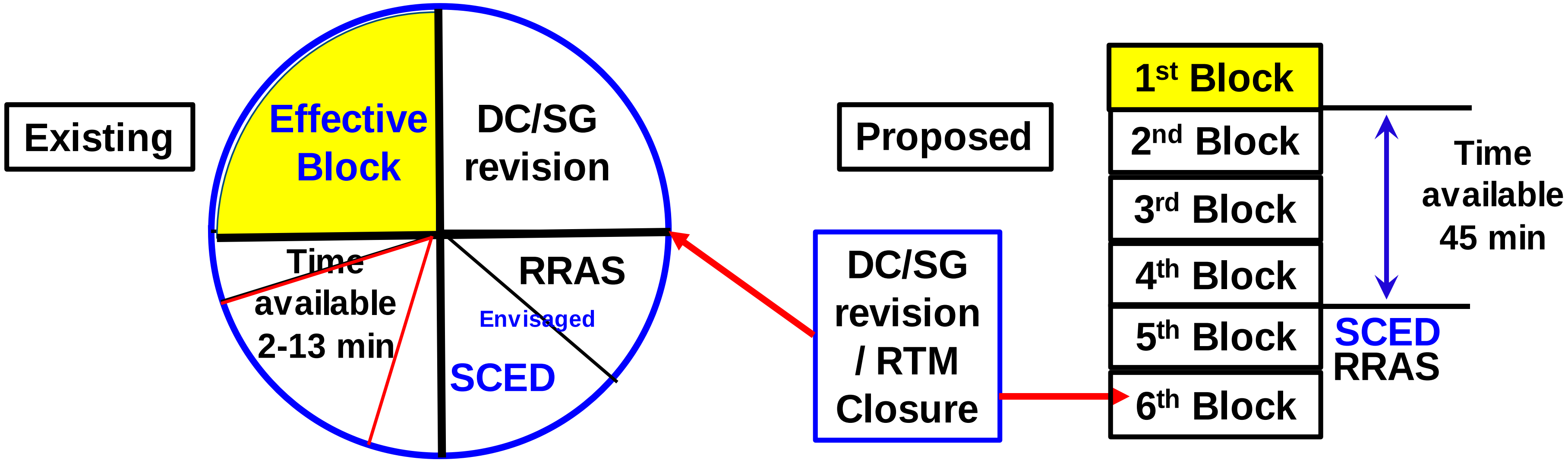
- **RRAS and SCED** scheduling mechanism shall also be prescribed in scheduling code of IEGC. Frequency of Schedule change due to SCED is very high (≈> 200 per day) as optimization software of SCED is run every block. Generators shall get enough time to adjust to new schedule. Regulatory intervention required for introducing early gate closure. Final schedule should be available 3 clear blocks in advance as enumerated below:



Other issues

- Demand Response from industrial/ commercial customers / automatic load shedding contracts may be introduced for peak power management.
- Part Load Compensation:
  - Finalisation of compensation for part load operation of gas projects
  - Part load operation compensation may be as recommended by CEA.
  - ANNUAL reconciliation for compensation is not logical
  - Regulated entity is liable to pay part load compensation. Beneficiaries are contesting as this is not mentioned clearly.
  - Compensation method to be made uniform across RPCs in case of SCED .
- Issuance of REA BY 2nd of every month.

THANK YOU

Power procurement through STOA

- **Issue**
- STOA transactions are treated as energy transactions even when it is contracted months ahead and accordingly gets prescheduled. On the day of delivery, the buyer has to take this energy even when cheaper options of energy is available to him.

- **Suggestion**
- It is suggested that STOA also should become capacity transaction and scheduled along with other MTOA/LTA capacity available.

IEGC - Contents

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Evolution of Grid Code

28th April 2010 : IEGC presently in force was notified by CERC

5th Mar 2012 : First amendment of IEGC notified

06th Jan 2014 : Second amendment of IEGC notified

07th Aug 2015 : Third amendment of IEGC notified

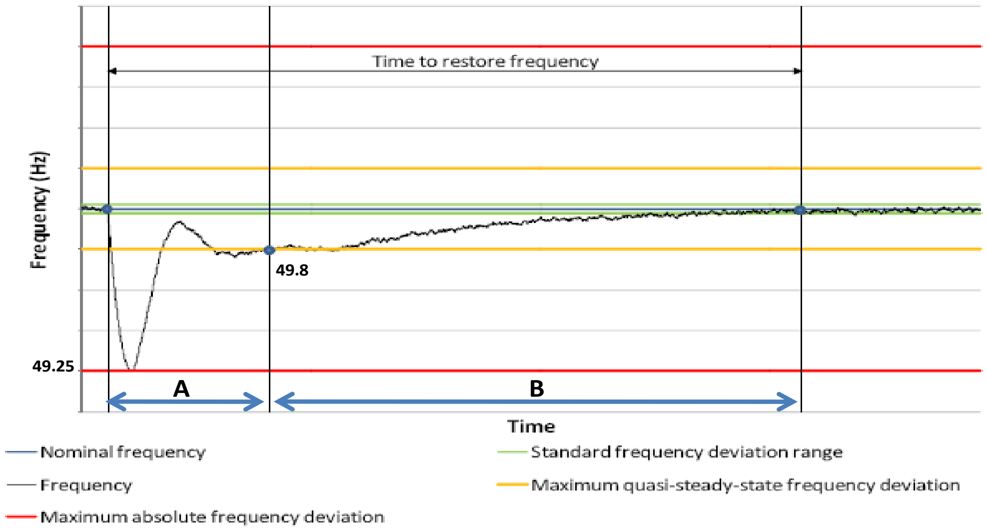
29th April 2016 : fourth amendment of IEGC notified

12th April 2017 : Fifth amendment of IEGC notified

Move to Nominal Frequency of 50 Hz

- **Issue**
- Expert Group for bringing power system operation closer to National Reference Frequency has recommended as under:
  - "To gradually phase out the RGMO by 1st April 2018 and instead have speed control with droop."
  - "CEA may notify the Technical Standards for connectivity to the grid in respect of RE generation at the earliest mandating primary control from RE resources also".
- Considering target frequency of 50 Hz and a quasi-steady state frequency of 49.8 Hz (Δf=-0.2 Hz) due to outage of largest power station in the country as a credible contingency, following example can be considered for keeping primary Up reserve.

Parameter	Unit	Peak Load
Demand	**MW**	**2,20,000**
Generation	**MW**	**2,20,000**
"Disturbance" Generation outage, ΔP_G	MW	**5000**
Post trip Generation, P_G' (= $P_G - \Delta P_G$)	MW	2,15,000
Capacity of Machines on Governor control to deliver primary UP response.	**MW**	**60,000**
D (Load Damping)**	MW/Hz	8,800
1/R (Governing)***	MW/Hz	24,000
AFRC, β = (D + 1/R)	MW/Hz	32,800
$\Delta f = \Delta P_G \div \beta$	**Hz**	**-0.15**
$f = f_N + \Delta f$	**Hz**	**49.85**
Load Damping will provide (MW)		**1341**
Governor response will provide (MW)		**3659**
Primary Reserve in % of Capacity of Machines earmarked to give UP response		**6.10**



Freq. decline can be arrested to -0.15 Hz (quasi Steady State Freq. at 49.8 Hz) if Primary Up reserve or Governor control is ensured on units (synchronized to Grid) having total capacity of ~ 60,000 MW only out of in service capacity of ~ 100,000 MW even during high RE scenario of 2021-22.

Nominal Frequency and Primary Reserve (RGMO/FGMO stipulation in IEGC)

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- RGMO / FGMO with Manual intervention in almost all machines as stipulated in the IEGC, even for machine with old mechanical governor, 50 MW and above Gas Turbines, wind turbines etc is not required.
- Even withholding (by restricting SG to normative DC) cheaper power of Pit head stations like Sipat, Rihand, Singrauli, Korba etc for the purpose of primary response is also against the theory of economic dispatch.

- **Suggestion**
- Our proposal is to identify and keep Primary UP Reserve margin in those machines whose variable cost is moderately high and operating at part load
- However all the machines in the system must *always be operated on Governor control* (not RGMO) and support frequency containment in the event of disturbances. Low cost generating units shall not keep any Primary UP Reserve Margin (like Sipat, Rihand, Singrauli, Korba etc) for the purpose of reducing power purchase cost of the consumers but these machines should participate during high frequency events by Governor Action to reduce generation.
- The prerequisite to run machines on Governor Control is to keep frequency within the governor dead band of target frequency of 50 Hz for >99% time by Secondary Control. Hence AGC in the form of *Secondary Control must be implemented across the country on war footing* and secondary reserves to be identified and maintained in those units by scheduling them for normal dispatch lower than DC. AGC reserves must be necessarily maintained in machines which are partially scheduled. Storage Hydro /CCGT units are most suited for this duty. Both up and down changes in generation level by AGC command must be commercially paid for.

Governor Droop Setting

- **Issue**
- Grid Code (Regulation 5.2(h)) prescribes that all thermal generators of 200 MW & above and all hydro generators of 10 MW & above shall be capable of picking load, in case of sudden frequency fall, up to 105 % and 110 % of their respective MCR.

- **Suggestion**
- For clarity on the above stipulation, it is proposed that the rate of frequency fall/change may be quantified in Hz/min in order to activate RGMO/FGMO.

AGC

- **Issue**
- AGC in various phases of implementation (one station per region) as pilot project as per CERC order.
    - NR – Dadri-II (successfully implemented)
    - WR – Mauda
    - ER – Barh
    - SR – Simhadri
    - NER – Bongaigaon
- CERC has also specified region wise secondary control reserves

- **Suggestion**
- Changes in Grid Code may be introduced for implementation of secondary control reserves.
- AGC should be implemented in all the units across the country

Ripple Factor

- **Issue**
- IEGC Regulation 5.2(f) (ii) b prescribes ripple factor of +/- 0.03 Hz to avoid frequent governor hunting which is very narrow considering International standards (+/- 0.06 Hz in USA) .

- **Suggestion**
- it may be revised to at least +/- 0.05 Hz in line with other developed countries.
- It will help in restricting primary control action more frequently in power system and frequency will remain in frequency band as prescribed above by 50 Hz Committee most of the time.