

CENTRAL ELECTRICITY REGULATORY COMMISSION

NEW DELHI

Draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Second Amendment) Regulations, 2026.

No. L-1/265/2022/CERC

Dated: 21.09.2026

Explanatory Memorandum

1. Background

1.1. Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2020 were notified on 29.05.2023 and are effective from 1.10.2023. So far, one amendment has been issued (the amended Regulations are hereinafter collectively referred to as the "Principal Regulations"). The current amendment is proposed in light of stakeholder feedback on various issues.

1.2. The draft Second Amendment mainly covers the following:

- 1) Incorporation of points as per Suo-moto Order dated 22.12.2024 in 11/SM/2024 and 05.10.2025 in 9/SM/2024.
- 2) Extension of the period of inter-change of power by RLDC
- 3) Reduction of the notice period for trial run.
- 4) Trial run of solar inverter units and wind turbines in NER and Sikkim
- 5) Minimum capacity of ESS for trial run
- 6) Provisions related to trial operation of pumped storage plants
- 7) Delay in demonstration of rated capacity due to transmission constraints
- 8) Provisions regarding automatic operation of pumped storage plants from the appropriate load despatch centre
- 9) Separate provision for declaration of COD of Pumped Storage Plants
- 10) Delinking of declaration of COD from the provisions under the PPA

- 11) Primary Response requirement for Pumped Storage Plant and Energy Storage System (except pumped storage plant)
 - 12) Revised methodology for estimation of reserves
 - 13) Incorporation of congestion charge provisions under the Grid Code and repeal of CERC (Measures to relieve congestion in real time operation) Regulations, 2009.
 - 14) Revision of high inflow Period for hydro generating plant.
 - 15) Regulation of access to defaulting entities which are defaulted in payment of various statutory charges payable under CERC Regulations.
 - 16) Incorporation of Procedure for scheduling of Free Power share of State Govt. from bus bar of a Central Hydro Generating Station and repeal of earlier procedure for scheduling of free power applicable for H.P.
 - 17) Supply of power from alternate sources in case of generating stations other than 62 with the express consent of buyer and mutual agreement on sharing of net savings.
 - 18) Revision of RTM Gate Closure timelines
2. In light of the Suo-Motu Orders dated 22.12.2024 in 11/SM/2024 and 05.10.2025 in 9/SM/2024, the relevant provisions of the Principal Regulations have been proposed to be amended. The detailed justifications for the proposed changes are already included in the said Suo-Moto Orders and are not repeated here for brevity. The following provisions are proposed to be incorporated in the Principal Regulations in light of the above Suo-moto Orders:
- (a) Regulation 22(3)(a): Trial run of Projects covered under Regulation 22(3)(a) of the Principal Regulations, having installed capacity of 250 MW or more, may be performed in instalments, with a minimum capacity of 50 MW in each instalment without any limit on the number of instalments. It is clarified that the trial run of solar inverter units up to 250 MW can be carried out in a maximum of five instalments (i.e. 1st instalment of 50 MW and the balance capacity in four instalments).

- (b) New Regulation 25A: The scheduling of infirm power post trial run and the treatment of such infirm power prior to declaration of the COD shall be in the following manner:

(1) The scheduling of infirm power shall be allowed only post issuance of a certificate of successful trial run as per Regulation 25 of these Regulations.

(2) If the generating station or ESS has entered into a contract either directly or through REIA or an intermediary procurer for sale of power from such generating station or ESS, and such contract has specific provisions for treatment of sale of power prior to achieving commercial operation, the same shall be scheduled to the buyer(s) as per the provisions of such Contract.

(3) In the absence of any specific provisions for the treatment of sale of power prior to achieving commercial operation under the contract,

(a) such power shall be first offered to the buyers with whom the generating station or ESS has entered into a contract either directly or through REIA or an intermediary procurer, with an advance notice of at least seven (7) days.

(b) If the buyer(s) give their consent to procure such power, the same shall be scheduled to the buyer(s) at a tariff mutually agreed between buyer(s) and the generating station.

(c) If the buyer(s) or the REIA or intermediary procurer do not respond within such notice period, it shall be considered as a deemed refusal of the buyer(s) or REIA or intermediary procurer and in such a case the generating station shall be free to sell such power to any third party outside the Contract.

- (c) Limit on declaration of Declared Capacity by Regional entity generating stations under Regulation 45(8)(a): The generating stations shall not be permitted to declare Peak hours DC less than off-peak hours DC, other than in cases of forced outage or partial outage. In case a generating station provides less DC during peak hours of the day than off-peak hours, the DC

for such generating station for the purpose of fixed charges shall be taken as the lower of the two.

(d) Provisions for Unit Shutdown and SCUC are proposed to be modified under Regulation 46 and Regulation 47, in view of directions under Order dated 05.10.2025 in 9/SM/2024.

(i) The timeline for proposing the unit to be taken under USD by a generating station, as provided in Order dated 05.10.2025 in 9/SM/2024, i.e., 1800 hrs, is proposed to be modified to 1430 hrs, and accordingly the timeline for all other subsequent activities shall also be revised. The revised timelines are proposed keeping in view that, as per the Order dated 05.10.2025, the generators have been allowed to take the unit under USD after SCUC run by NLDC. However, as the SCUC is the last step to commit a generating station up to its minimum turndown level. Accordingly, the changes in the existing timelines allowed vide Order dated 05.10.2025 in 9/SM/2024 are proposed to be modified. A table depicting the existing and proposed timelines and activities to be carried out from 1400 hrs onward is as under:

Activity	Existing timeline	Proposed timeline
NLDC shall publish a tentative list of generating stations or units thereof, which are likely to be scheduled below the minimum turndown level	14:00 Hrs.	14:00 Hrs.
Generating station shall inform the RLDC and beneficiaries of the proposed unit(s) to be taken under USD	18:00 Hrs*	14:30 Hrs.
Beneficiaries may revise schedules to retain such units on-bar by ensuring scheduling of at least 50% MCR for all time blocks	19:00 Hrs.*	15:30 Hrs.
Revised requisitions from the said generating stations shall be final and binding, and further reduction in the drawal schedule shall not be allowed from such stations except when the	NA	15:30 Hrs.

generating stations remain above the minimum turn-down level.		
The generating station may declare units under USD if the schedule of at least 50% of MCR in all time blocks is not achieved.	NA	16:00 Hrs.
NLDC shall prepare the final list of such generating units that are likely to go below their minimum turndown level, and such generating units shall be stacked as per merit order	After 14:30 Hrs	After 16:30 Hrs.
NLDC may schedule incremental energy from the generating units, so as to bring such units to their minimum turndown level in order to maximise availability of on-bar units	15:00 Hrs.	17:00 Hrs.
The generating station shall inform the RLDC and beneficiaries of the unit(s) to be taken under USD.	20:00 Hrs*	18:00 Hrs.

* as per Order dated 05.10.2025 in 9/SM/2024.

- (ii) It is also provided that NLDC may run SCUC at any time of the day to commit or decommit a unit for managing the grid security. In case of decommitting a unit or station thereof, the schedules of such station or unit shall be adjusted as per the proposed Procedure at Annexure-9.
- (iii) It is also clarified that the issue of putting off-take obligation on the beneficiaries is being raised by the stakeholders so as to avoid infeasible scheduling by the beneficiaries. It is further observed that requisitions provided by beneficiaries less than MTL are affecting grid security and reasonable operation of the thermal generating stations. Thus, the responsibility for providing an operationally feasible schedule also lies with the beneficiaries as well. However, keeping in view that beneficiaries' portfolio also includes the RE demand as well as internal generation, accordingly, the off-take obligation is not proposed to be incorporated at this stage. However, it is expected that beneficiaries shall provide a feasible schedule to the generating station or unit thereof.

3. Amendment to Regulation 19: Extension of period of inter-change of power by RLDC

3.1 Regulation 19 of the Principal Regulations provides as under.

“(2) The period for which such inter-change shall be allowed shall be as follows:-

- (a) Drawal of start-up power shall not exceed 15 months prior to the expected date of first synchronization and one year after the date of first synchronization; and*
- (b) Injection of infirm power shall not exceed one year from the date of first synchronization for generating stations other than REGS and ESS (except Hydro PSP ESS).*
- (c) Injection of infirm power shall not exceed 45 (forty-five) days from date of first time energization and integration (FTC) approval for REGS and ESS (except Hydro PSP ESS).*

(3) Notwithstanding the provisions of clause (2) of this Regulation, the Commission may allow extension of the period for inter-change of power beyond the stipulated period on an application made by the generating station at least two months in advance of the completion of the stipulated period.

Provided that for REGS and ESS (except Hydro PSP ESS), extension of period for injection of infirm power beyond the stipulated period may be allowed (a) for a period up to three months by respective RLDC on an application(s) made by such generating station or ESS (except Hydro PSP ESS) to respective RLDC along with detailed reasons, at least 10 days in advance of the completion of the stipulated period.”

3.2 As per the above, the Principal Regulations provide for a time of 45 days for inter-change of power from the date of first-time energization and integration (FTC) approval for REGS and ESS (except Hydro PSP ESS). A three-month extension is to be granted by RLDC beyond a period of 45 days, on an application(s) made by such generating station or ESS.

3.3 It has been noted in some cases that the generating stations are approaching the RLDC, seeking time extension after the expiry of three months and no status is updated to the RLDCs after the expiry of the timeline of 45 days allowed in the Principal Regulations. Ideally, a generating station should intimate the concerned RLDC in advance if it is not in a position to complete the testing and commissioning activities within the stipulated timeline. And seek further extension if required.

3.4 Accordingly, it has been proposed that concerned REGS and ESS (except hydro PSP) shall inform the detailed reasons for delay, if any, in completion of testing and commissioning and achieving the COD, to the concerned RLDC, along with a likely date by which it will make a request seeking extension of the period for inter-change of power. Further, the request seeking extension of the period for inter-change of power shall be made at least 10 days prior to the requested start date of inter-change of power. Based on the request of the generating station, RLDC may allow the extension for inter-change of power. The RLDC may allow multiple

extensions with a cumulative time extension for three months. The concerned generating station shall also update the status of testing and commissioning activities for which extension is sought to the RLDC on a monthly basis.

4. Amendment to Regulation 21: Reduction of Notice period for trial run

4.1 Regulation 21(1) of the Principal Regulations provides as under.

" 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 RLDC, and the beneficiaries of the generating stations, including intermediary procurers, wherever identified:

Provided that in case the repeat trial run is to take place within forty eight (48) hours of the failed trial run, fresh notice shall not be required,"

As per the above, a generating company is required to give a notice of at least 7 days to the concerned RLDC and the beneficiaries of the generating stations, including intermediary procurers, for a trial run or repeat trial run.

4.2 National Solar Energy Federation of India (NSEFI) vide e-mail dated 12.02.2025

Submitted as under:

"1. Reduction of Trial Run Notice Period: The current notice period under IEGC, 2023 should be reduced from seven (7) days to three (3) days."

As per the above, NSEFI suggested reducing the Notice Period for trial run under the Grid Code from seven (7) days to three (3) days.

4.3 We observe that in the Principal Regulation, a timeline of seven (7) days was provided so as to give sufficient time to the concerned buyers to witness the trial run tests physically. However, based on feedback received from the NSEFI to reduce the said timeline, we are of the view that there are no reasons to wait for seven days once the generating unit is ready for the trial operation. Accordingly, it is proposed to reduce the notice period for trial run from seven (7) days to three (3) days.

5. Amendment to Regulation 22 (3)(a) and 22(3)(c): Trial Run of Solar inverter units and wind turbines in NER and Sikkim:

5.1 Regulation 22(3)(a) of the Principal Regulations provides as under:

"(a) Trial run of the solar inverter unit(s) shall be performed for a minimum capacity aggregating to 50 MW:

Provided that in the case of a project having a capacity of more than 50 MW, the trial run for the balance capacity shall be performed in a maximum of four instalments with a minimum capacity of 5 MW:

Provided further that the trial run for solar inverter unit(s) aggregating to less than 50 MW for entities covered under clause (e) of Regulation 4.1 of the GNA Regulations, shall be allowed for the capacity for which Connectivity has been granted to such entity.”

As per the above, the trial run of solar inverter units is allowed for a minimum capacity of 50 MW except for solar inverter units covered under clause (e) of Regulation 4.1 of the GNA Regulations.

5.2 Regulation 4.1(f) of the GNA Regulations, 2022 provides as under:

“4.1. The following entities shall be eligible as Applicants to apply for grant of Connectivity or for enhancement of the quantum of Connectivity:

....

(f) Notwithstanding anything contained under Clauses (a) to (c) of this Regulation, the minimum installed capacity individually or with an aggregate installed capacity to apply for a grant of Connectivity shall be 25 MW in North Eastern Region (NER) and Sikkim.”

As per the above, for NER and Sikkim, the minimum installed capacity, individually or in aggregate installed capacity, to apply for a grant of Connectivity is 25 MW.

5.3 Regulation 4.4 of the GNA Regulations, 2022 provides as under:

“4.4 Bhakra Beas Management Board (BBMB) system having been declared as ISTS, application for grant of Connectivity to REGS or ESS seeking to get connected to the transmission network of BBMB, which is not covered under Regulation 4.1 of these regulations, shall be made and processed as specified under clauses 4.4.1 to 4.4.4 of this Regulation:

4.4.1 A REGS or ESS with an Installed capacity 5 MW and above but less than 50 MW, either individually or collectively through a Lead Generator, or Lead ESS, as the case may be, owned and operated by BBMB or selected by BBMB for implementation based on competitive bidding, may seek Connectivity to the BBMB network comprising of a substation or transmission line of BBMB. Such entity shall furnish an application to the Nodal agency, with application fee of Rs 5 lac/application and the system study conducted by BBMB for such an entity.

4.4.2 The REGS or ESS covered under clause 4.4.1 of this Regulation shall comply with the provisions of submission of LOA or PPA or Land or BG in lieu of land (under Regulation 5.8 of these regulations), Conn-BG1, Conn-BG2, Conn-BG3 (under Regulation 8 of these regulations) and One-time GNA charges (under Regulation 40.2 of these regulations).

4.4.3 A REGS or ESS with an installed capacity of less than 5 MW, owned and operated by BBMB or selected by BBMB for implementation based on competitive bidding, may seek Connectivity to the BBMB network, comprising a substation or transmission line or switchyard of a generating station of BBMB, by applying to BBMB SLDC for such connectivity and after approval of BBMB SLDC, may get connected to the network of BBMB. The approval of SLDC shall be forwarded to the Nodal Agency for records, along with a fee of Rs 5 lac/ project.

4.4.4 For REGS or ESS covered under clause 4.4.3 of this Regulation, the provisions of submission of LOA or PPA or Land or BG in lieu of land (under Regulation 5.8 of these regulations), Conn-BG1, Conn-BG2, Conn-BG3 (under Regulation 8 of these regulations) and One-time GNA charges (under Regulation 40.2 of these regulations) shall not be applicable.”

As per the above, for BBMB, the minimum installed capacity, individually or with an aggregate installed capacity, to apply for a grant of Connectivity is less than 50 MW.

5.4 Accordingly, Regulation 22 (3)(a) of the Principal Regulations is proposed to be amended so as to include the provisions for trial run of projects having a capacity less than 50 MW in NER and Sikkim and entities of BBMB covered under Regulation 4.1(f) and Regulation 4.4 of GNA Regulations.

5.5 On similar lines, Regulation 22(3)(c) with regard to trial run of wind turbines is also proposed to be amended.

6. Minimum capacity of ESS for trial run

6.1 Regulation 22(3)(e) of the Principal Regulations provides as under:

“(3) Trial Run of Wind / Solar / ESS / Hybrid Generating Station

.....

(e) 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.”

As per the above, the Principal Regulations do not specify the minimum capacity of ESS for the purpose of trial run.

6.2 NLDC vide its letter dated 08.04.2026 submitted as under:

“This is to submit before the Hon'ble Commission that Clauses 21 (3)(a) and 21 (3)(c) of the Indian Electricity Grid Code (IEGC) 2023, prescribe a minimum capacity of 50 MW for conducting trial runs of solar and wind generating stations.

Further, Clause 21(3)(e) of IEGC 2023 pertaining to trial run of standalone Energy Storage Systems (ESS) states that

“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.”

In order to ensure uniformity and consistency with all renewable generating resources, a minimum capacity of 50 MW has been considered for trial runs of ESS, in line with the provisions applicable to solar and wind projects. This approach is expected to maintain parity across technologies, provide clarity to developers, and ensure that trial runs are conducted at a scale that is meaningful for grid integration and performance validation.

This is for your kind information and further directions if any.”

As per the above, NLDC has submitted that it is considering a minimum capacity of 50 MW for a trial run of ESS in line with the provisions applicable to solar and wind projects.

- 6.3 We have noted the submissions of NLDC and observed that, as per the existing Regulations, no minimum capacity has been specified under the Principal Regulations for performing the trial run of ESS. Accordingly, in line with NLDC's submissions, it is proposed to incorporate a minimum capacity of 50 MW for conducting a trial run of an Energy Storage System (ESS).
- 6.4 We also note that under sub-clause (e) and (f) of Regulation 4.1 and Regulation 4.4 of the GNA Regulations, standalone ESS with an installed capacity below 50 MW are also eligible as Applicants to apply for grant of Connectivity. Accordingly, such an ESS shall be allowed for the trial run of such capacity for which connectivity has been allowed under the GNA Regulations.
- 6.5 The provisions for the trial run of ESS having capacity up to 250 MW and above 250 MW are proposed to be incorporated in line with the provisions applicable to the solar generating stations.
- 6.6 As per the proposed amendment, a standalone Energy Storage System (ESS) (excluding Pumped Storage Plant) having an installed capacity of 250 MW or more, may be performed in instalments, with a minimum capacity of 50 MW in each instalment without any limit on the number of instalments. It is clarified that the trial run of solar inverter units up to 250 MW can be carried out in a maximum of five instalments (i.e. 1st instalment of 50 MW and balance capacity in four instalments).
- 6.7 It is also clarified that since the provision for trial run of pumped storage plant is specified separately, Regulation 22(3)(e) shall be applicable for trial run of ESS (excluding Pumped Storage Plant).

7. Amendment to Regulation 22(3)(f): Trial run of pumped storage plant.

- 7.1 Regulation 22 (3)(f) of the Principal Regulations provides as under.

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

Provided that if it is not possible to demonstrate the design capabilities up to the rated water drawing levels due to insufficient reservoir levels, the COD may be declared after

demonstrating the capabilities at available water drawing levels, subject to the condition that design capabilities up to the rated water drawing levels shall be demonstrated immediately when sufficient reservoir level is available after COD.

Provided further that if such a generating station is not able to demonstrate the design capabilities when sufficient water is available, the generating company shall have the option to either go for a repeat trial run or de-rate the capacity. If the generating company decides to de-rate the unit capacity in terms of sub-clause (b) of Clause (2) of Regulation 22 of these Regulations, such de-rating shall be effective from the COD.”

As per the above, the existing Regulations provide for the trial run of a pumped storage plant.

7.2 SRLDC, vide its letter dated 10.05.2025, submitted as under:

“Issue 1: Trial run of Pumped Storage Plants to be done Unit-wise or all units of the entire plant- in one go?”

....

From the aforesaid clause, it appears that the trial run requirement applies to the entire PSP plant in single go and not a unit-wise basis. It is pertinent to mention that IEGC 2023 and its SOR, do not explicitly define the term “Pumped Storage Plant”. Therefore, there is a grey area whether trial run to be done unit wise or the PSP plant as a whole.

It is our understanding from the harmonious reading of Regulation 22 in general and Regulation 22(3)(f) in particular, that trial run should be performed for a PSP plant on a unit wise basis- i.e. one unit at a time which is implementable from a particular standpoint.

....

Issue 2: Treatment of Interruption during trial run of energy storage units including PSP:

“As per IEGC Regulation 22(2)(a) a conventional hydro generating unit shall be in continuous operation for twelve (12) hours at MCR to achieve successful trial run and short interruption or load reduction of cumulative 4 Hrs is permissible with a corresponding increase in duration of the test. But in case of PSP units, it is not specified as to how to treat such instances of interruption or partial loading. It is felt that being a part of the hydro unit, similar provision could be extended to the PSP units undergoing trial run in pumping mode.”

As per the above, SRLDC has sought clarifications with respect to trial run provisions under the Principal regulations for pumped storage plants.

7.3 We observe that since a pumped storage plant may have a number of units and therefore there is no basis to wait for other units to be ready for conducting the trial run of the unit which is ready. Accordingly, it is clarified that the trial run of the pumped storage plant is to be carried out on a unit-wise basis. Accordingly, the proposed amendment.

7.4 Further, with regard to the clarification sought by the SRLDC for interruptions during trial run, we are of the view that a pumped storage plant works on the same principles as a hydro generating station; accordingly, on the analogy of trial run provisions of a hydro generating station, similar provisions with regard to interruptions, partial loading, repeat trial run and derating are proposed to be incorporated for a pumped storage plant.

8. Amendment to Regulation 22 (3): Delay in demonstration of rated capacity due to transmission constraints

8.1 Regulation 22(3) of the Grid Code provides as under:

“(3) Trial Run of Wind / Solar / ESS / Hybrid Generating Station

(a) Trial run of the solar inverter unit(s) shall be performed for a minimum capacity aggregating to 50 MW:

Provided that in the case of a project having a capacity of more than 50 MW, the trial run for the balance capacity shall be performed in a maximum of four instalments with a minimum capacity of 5 MW:

Provided further that the trial run for solar inverter unit(s) aggregating to less than 50 MW for entities covered under clause (e) of Regulation 4.1 of the GNA Regulations, shall be allowed for the capacity for which Connectivity has been granted to such entity.

(b) Successful trial run of a solar inverter unit(s) covered under sub-clause (a) of this clause shall mean the flow of power and communication signal for not less than four (4) hours on a cumulative basis between sunrise and sunset in a single day with the requisite metering system, power plant controller, telemetry and protection system in service. The generating company shall record the output of the unit(s) during the trial run and shall corroborate its performance with the temperature and solar irradiation recorded at site during the day and plant design parameters:

Provided that:

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

(ii) if it is not possible to demonstrate the rated capacity of the plant due to insufficient solar irradiation, COD may be declared subject to the condition that the same shall be demonstrated immediately when sufficient solar irradiation is available after COD, within one year from the date of COD:

Provided that if such a generating station is not able to demonstrate the rated capacity when sufficient solar irradiation is available after COD, the generating company shall de-rate the capacity in terms of sub-clause (h) of clause (3) of this Regulation.

(c) Trial run of a wind turbine(s) shall be performed for a minimum capacity aggregating to 50 MW:

Provided that in the case of a project having a capacity of more than 50 MW, the trial run for wind turbine(s) above the capacity of 50 MW shall be performed in batch sizes of not less than 5 MW:

Provided further that the trial run for wind turbine(s) aggregating to less than 50 MW for entities covered under clause (e) of Regulation 4.1 of the GNA Regulations, shall be allowed for the capacity for which Connectivity has been granted to such an entity.

(d) Successful trial run of a wind turbine(s) covered under sub-clause (c) of this clause shall mean the flow of power and communication signal for a period of not less than four (4) hours on a cumulative basis in a single day during periods of wind availability with the requisite metering system, power plant controller, telemetry and protection system in service. The generating company shall record the output of the unit(s) during the trial run and corroborate its performance with the wind speed recorded at the site(s) during the day and plant design parameters:

Provided that-

(i) the output below the corroborated performance level with the wind speed of the day shall call for a repeat of the trial run;

(ii) if it is not possible to demonstrate the rated capacity of the plant due to insufficient wind velocity, COD may be declared subject to the condition that the same shall be demonstrated immediately when sufficient wind velocity is available after COD, within one year from the date of COD:

Provided that if such a generating station is not able to demonstrate the rated capacity when sufficient wind velocity is available after COD, the generating company shall de-rate the capacity in terms of sub-clause (h) of clause (3) this Regulation.”

As per the above, a maximum period of one year is allowed from the date of COD to demonstrate the rated capacity of the plant if it is not possible to demonstrate the rated capacity during trial run due to insufficient wind velocity or insufficient solar irradiation.

8.2 Ayana Renewable Power Private Limited, vide its letter dated 03.11.2025, submitted as under:

“Request for modification in the existing Hon. CERC IEGC -

As per the IEGC provisions (above), regarding the trial run, it is clear that if RE generating station (Wind/Solar) is not able to demonstrate the rated capacity when sufficient solar irradiation or wind velocity is available after COD, within one year, the generating company shall have the option to either go for a repeat trial run or de-rate the capacity. However, due to one year provision, this is being interpreted contrary to available relief and is resulting in denying an opportunity for a repeat trial, when sufficient opportunity is available.

Further, the regulation does not cover the cases where the failure of demonstration of the rated capacity was due to reasons beyond control of the generating system, like breakdown, non-availability of evacuation/sufficient evacuation, T-GNA, curtailment instructions by RLDC, ROW, weather disruptions etc. Hence, we suggest that, in such cases, the generating station deserves a genuine second opportunity for demonstrating the rated capacity of its unit, in the next available sufficient solar irradiation or wind velocity (as applicable).

With the above issue, and lack of clear interpretation with respect to the existing regulations, renewable projects like ours (ARPTPL) are facing difficulties in obtaining their final COD certificates from the RLDCs.”

As per the above, Ayana has submitted that the failure of demonstration of the rated capacity due to reasons beyond the control of the generating system, such as breakdown, non-availability of evacuation/sufficient evacuation, T-GNA, curtailment instructions by RLDC, ROW, weather disruptions, etc., are not covered under the Regulations.

8.3 With regard to the suggestions of Ayana, we observe that a time of one year is already provided under the Regulations and such a period is sufficient to cover the events mentioned by Ayana, such as breakdown, curtailment instructions by RLDC, ROW, weather disruptions, etc. However, we observe that in a number of cases the transmission infrastructure required for the evacuation of power is delayed substantially and even beyond a period of one year. In such cases, the generating station would not be able to demonstrate its rated capacity within one year due to insufficient transmission infrastructure.

8.4 In view of the above, it is proposed that if there is a transmission constraint and the generating station is not able to demonstrate its rated capacity, such generating station may be allowed to demonstrate the rated capacity of the plant within one year from the date of effectiveness of its GNA or one year from its COD, whichever is later. Accordingly, a new sub-clause (j) is proposed to be added after sub-clause (i) of Clause (3) of Regulation 22.

9. Amendment to Regulation 24(2): Provisions regarding automatic operation of pumped storage plants and ESS from the appropriate load despatch centre

9.1 Regulation 24(2) of the Principal Regulations provides as under:

“(2) All thermal generating stations having a capacity of more than 200 MW and hydro generating stations having a capacity of more than 25 MW shall submit documents confirming the enablement of automatic operation of the plant from the appropriate load despatch centre by integrating the controls and tele-metering features of their system into the automatic generation control in accordance with the CEA Technical Standards for Construction and the CEA Technical Standards for Connectivity.”

As per the above, the Principal Regulations provide for enablement of automatic operation of the thermal generating stations having a capacity of more than 200 MW and hydro generating stations having a capacity of more than 25 MW.

- 9.2 The above provisions of principal regulations with regard to enablement of automatic operation of the plant from the appropriate load despatch centre need to be clarified for their applicability to the Energy Storage Systems.
- 9.3 With the rapid growth of intermittent solar and wind generation, the automatic operation of an Energy Storage System (including PSP) directly from a Load Despatch Centre is essential to maintain grid stability and operational efficiency. Integrating ESS with automatic operation from a Load Despatch Centre will enable instant absorption of excess renewable energy during peak hours and release it the moment renewable energy generation drops. In this regard, as a hydro generating station and pumped storage power plant in generation mode operates on the same principles, accordingly a pumped storage plant in generation mode is also required to meet the technical requirements as applicable to a hydro generating station. Similarly, an Energy Storage System (excluding PSP) with a capacity of 25 MW and above shall also be required to enable the automatic operation from the appropriate load despatch centre.
- 9.4 In view of the above, Regulation 24(2) of the Principal Regulations is proposed to be amended so as to include a pumped storage plant with a capacity of more than 25 MW and an Energy Storage System (excluding PSP) with installed capacity of 25 MW and above. Consequently, similar changes are proposed under Regulation 13(11)(w).

10. Amendment to Regulation 27: Separate provision for declaration of COD of Pumped Storage Plants

- 10.1 Regulation 27(1) of the Principal Regulations provides as under:

“(1) A generating station or unit thereof or a transmission system or an element thereof or ESS may declare commercial operation as follows and inform CEA, the concerned RLDC, the concerned RPC and its beneficiaries:

....

(b) Hydro Generating Station

*(i) The commercial operation date in the case of a unit of the hydro generating station including a **pumped storage hydro generating station** shall be the date declared by the generating station after a successful trial run at MCR or derated capacity as per sub-clause (b) of clause (2) of Regulation 22 of these regulations, as the case may be, and submission of a declaration as per clause (2) of Regulation 26 of these regulations.*

(ii) In the case of the generating station, the COD of the last unit of the generating station shall be considered as the COD of the generating station.”

As per the above, the Principal Regulations provide for informing the CEA, the concerned RLDC, the concerned RPC and its beneficiaries after declaration of COD. Further, the Principal Regulations also provide for declaration of COD of a unit of the hydro generating station, including a pumped storage hydro generating station.

10.2 Sharing of information about the declaration of commercial operation to the Central Transmission Utility is proposed to be incorporated under Regulation 27(1), as the Central Transmission Utility looks after the various compliances under the GNA regulations as well as Sharing regulations.

10.3 In the above paragraphs, we have clarified that the trial run of a pumped storage plant may be carried out on a unit-wise basis. Accordingly, the COD of the pumped storage plant may also be carried out on a unit-wise basis. Since the provision for trial operation of a pumped storage plant has been proposed to be separated from a hydro generating station, we are of the view that the Principal Regulations may also include a separate provision for COD of a pumped storage plant. Therefore, a new sub-clause (b-i) is proposed to be inserted after sub-clause (b) of Clause (1) of Regulation 27 of the Principal Regulations. Accordingly, the words “including a pumped storage hydro generating station” shall be deleted in sub-clause (b)(i) of Clause (1) of Regulation 27 of the Principal Regulations.

11. Amendment to Regulation 27(e)(i): Delinking of declaration of COD from the provisions under the PPA.

11.1 Regulation 27(1)(e) of the Principal Regulations provides as under:

“(e) Generating Stations based on Wind and Solar resources; ESS and Hybrid Generating Station

(i) The commercial operation date in the case of units of a renewable generating station aggregating to 50 MW and above or such other limit as specified in clause (3) of Regulation 22 of these regulations, shall mean the date declared by the generating station after undergoing a 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 the case of a 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.”

11.2 As per the above, the commercial operation of a renewable generating station is to be declared subject to the fulfilment of the conditions as per the PPA.

11.3 We observe in recent cases where multiple generating stations located at different locations are part of one bid as a renewable hybrid projects, do not declare the COD of their individual generating stations for long durations, citing that one component (generating station) of the project is ready and the other generating station is not ready. Further, under the Contract provisions, COD shall be declared only after both generating stations under the hybrid project are ready. Therefore, such generating stations continue to inject infirm power, citing non-readiness of the other generating stations.

11.4 We are of the view that the generating station which is ready should be declared under commercial operation once the trial run has been completed as per provisions of the Grid Code. There is no reason to delay the declaration of COD for such long durations. However, power supply under the PPA shall start only after fulfilment of conditions under the respective Contract. Accordingly, an amendment is proposed under Regulation 27(e)(i) of the principal regulations.

11.5 Since Regulations 27(1)(e)(i) is applicable to ESS as well, the words “or ESS” are proposed to be added in Regulation 27(e)(i).

12. Amendment to Regulation 30(10): Primary Response requirement for Pumped Storage Plant and Energy Storage System (except pumped storage plant)

12.1 Sub-clause (g) and (h) of Clause (10) of Regulation 30 of the Principal Regulations provide as under:

“(g) All the generating units shall have their governors or frequency controllers in operation all the time with droop settings of 3 to 6 % (for thermal generating units and WS Seller) or 0-10% (for hydro generating units) as specified in the CEA Technical Standards for Connectivity.

(h) The primary response requirement shall be as mentioned in Table 4.

TABLE 4: PRIMARY RESPONSE OF VARIOUS TYPES OF GENERATING UNITS

Fuel/ Source	Minimum unit size/Capacity	Up to
<i>Coal/Lignite Based</i>	<i>200 MW and above</i>	<i>±5% of MCR</i>
<i>Hydro</i>	<i>25 MW and above</i>	<i>±10% of MCR</i>
<i>Gas based</i>	<i>Gas Turbine above 50 MW</i>	<i>±5% of MCR (corrected for ambient temperature)</i>

Fuel/ Source	Minimum unit size/Capacity	Up to
WS Seller (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	As per CEA Technical Standards for Connectivity

“

As per the above, the primary response requirements of the sources based on Coal/Lignite, Hydro, Gas-based and WS Seller are specified under the Principal regulations.

12.2 Central Electricity Authority (Technical Standards for Connectivity to the Grid), Regulations, 2007 and amendment thereof, provides as under:

“A. Connectivity Standards applicable to the Generating Stations other than wind and generating stations using inverters

These generating stations shall comply with the following requirements besides the general connectivity conditions given in the said regulations and Part I of the schedule:-

A1. For Generating stations which are connected on or after the date on which Central Electricity Authority (Technical Standards for Connectivity of the Grid) Regulation, 2007 became effective

....

(4) All generating machines irrespective of capacity shall have electronically controlled governing system with appropriate speed/load characteristics to regulate frequency. The governors of thermal generating units shall have a droop of 3 to 6% and those of hydro generating units 0 to 10%.

...

B. Connectivity standards applicable to the wind generating stations, generating stations using inverters, wind - solar photo voltaic hybrid systems and energy storage systems.

The generating stations shall comply with the following requirements in addition to the general connectivity conditions specified under Part 1:

Provided that the energy storage systems shall comply, only with the requirements specified under clause B1 in addition to the general connectivity conditions specified under Part 1.;

B2. For generating station getting connected on or after completion of 6 months from date of publication of these Regulations in the Official Gazette.

(4) The generating stations with installed capacity of more than 10 MW connected at voltage level of 33 kV and above –

(i) shall be equipped with the facility to control active power injection in accordance with a set point, capable of being revised based on directions of the State Load Dispatch Centre or Regional Load Dispatch Centre, as the case may be;

(ii) shall have governors or frequency controllers of the units at a droop of 3 to 6% and a dead band not exceeding ± 0.03 Hz.”

As per the above, the CEA standards provide for a droop setting of 3-6% for thermal generating units and renewable generating stations and 0-10% for hydro generating stations.

12.3 NLDC, vide its letter dated 02.03.2026, submitted as under:

“Proposal for the incorporation of Energy Storage Systems (ESS) into the Primary frequency response framework of the Indian Electricity Grid Code (IEGC) 2023.

As India accelerates its transition towards a renewable energy-dominated power sector, with a target of 500 GW non-fossil fuel capacity by 2030, the integration of variable renewable energy sources like solar and wind poses significant challenges to grid stability, including frequency fluctuations and supply-demand mismatches. Primary Reserve Ancillary Service (PRAS) is essential for maintaining grid frequency within the operational band, providing rapid response to deviations, and ensuring reliable power supply. Energy Storage Systems (ESS), particularly Battery Energy Storage Systems (BESS) and Pumped Storage Plants (PSP), are critical for delivering PRAS due to their fast-ramping capabilities, high efficiency, and ability to store and dispatch energy on demand.

As per the Central Electricity Authority's National Electricity Plan (NEP) 2023, India is set to integrate significant energy storage capacity into the grid, with a strong emphasis on BESS and PSP, which will be central to delivering PRAS for grid stability and renewable integration. By FY 2026-27, the installed capacities are expected to reach 7.7 GW of BESS and 7.4 GW of PSP, while the CEA's Optimal Generation Mix projects a scale-up to 41 GW of BESS and 19 GW of PSP by 2030. This expansion underscores the urgent need for grid flexibility, as rising renewable penetration leads to sharper and more frequent ramps. ESS solutions such as BESS and PSP provide rapid response and high operational flexibility, making them indispensable for ensuring reliability and supporting India's clean-energy transition.

Incorporating these resources into the regulatory framework for PRAS is a grid security imperative, enabling the National Load Despatch Centre (NLDC) to issue frequency response obligations (FRO) across control areas, as per IEGC 2023. This inclusion will formalize their role in primary frequency control, enhancing system inertia and resilience against disturbances, while aligning with India's energy security goals.

Furthermore, the capability of BESS and PSP for providing primary frequency response are being tested during FTC and trial run compliance verifications, in accordance with CERC IEGC 2023 and CEA (Technical Standards for Connectivity to the Grid) Regulations 2007, as amended from time to time.”

.....

2. Proposed Revision in Table 4 under Clause 30(10)(h) and clause 30(10)(g) of IEGC 2023

Clause 30(10)(e) quoted below empowers NLDC to identify other resources, such as ESS and demand resources, to provide PRAS.

quote

"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 Ancillary Services Regulations."

unquote

The current Table 4 under Clause 30(10)(h) of IEGC does not explicitly mandate primary frequency response from emerging technologies like BESS and Pumped storage hydro plants. Inclusion of these emerging technology assets in Table 4 of the IEGC will provide an explicit regulatory basis for NLDC to issue FRO by duly accounting for such resources in the frequency response framework.

Accordingly, it is proposed to amend Table 4 - to include ESS (PSP and BESS) to formalize their contribution to the grid's primary frequency response as detailed below.

Fuel/ Source	Minimum unit size/Capacity	Up to
Coal/Lignite Based	200 MW and above	±5% of MCR
Hydro	25 MW and above	±10% of MCR
Gas based	Gas Turbine above 50 MW	±5% of MCR (corrected for ambience temperature)
WS Seller (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	As per CEA Technical Standards for Connectivity
Pumped Storage Plant (PSP)	25 MW and above	As per CEA Technical Standards *
Battery Energy Storage (BESS)	10 MW and above connected at 33 kV and above	As per CEA Technical Standards *

Note: A comprehensive revision of the CEA Technical Standards (2025) is presently under drafting.

Further, Clause 30(10)(g) may be amended as below to include ESS technologies:

"(g) All the generating units and Energy Storage Systems (ESS) shall have their governors or frequency controllers in operation all the time with droop settings of 3 to 6 % (for thermal generating units and WS Seller) or 0-10% (for hydro generating units and ESS) as specified in the CEA Technical Standards for Connectivity."

12.4 As per the above, NLDC has submitted that the Battery Energy Storage Systems (BESS) and Pumped Storage Plants (PSP) are critical for delivering PRAS due to their fast-ramping capabilities, high efficiency, and ability to store and dispatch energy

on demand and that incorporating these resources into the regulatory framework for PRAS is a grid security imperative, which will enable NLDC to issue frequency response obligations (FRO) across control areas. Accordingly, NLDC has suggested including ESS (PSP and BESS) to formalise their contribution to the grid's primary frequency response. NLDC has also suggested including ESS under Regulation 30(10)(g) regarding droop settings. NLDC has proposed a droop setting of 0-10% for energy storage systems.

12.5 CEA has also published Draft Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2026 on 31.7.2026 inviting public comments, which provide as under:

“Chapter – II

Requirements for Generators and ESS

Synchronous Generating Station

....

34. All generating unit(s) irrespective of capacity shall have electronically controlled governing systems with appropriate speed/load characteristics to regulate frequency. The governors of thermal generating unit(s) shall have a droop of 3 to 6% of MCR and hydro generating unit(s) including PSP shall have a droop of 0 to 10% of MCR.

....

Asynchronous Generating Station

75. The generating station with installed capacity of more than 10 MW connected at voltage level of 33 kV and above:

(1) shall be equipped with the facility to control active power injection in accordance with a set point, capable of being revised based on directions of the State Load Despatch Centre or Regional Load Despatch Centre, as the case may be;

(2) The frequency controller shall be set with respect to a reference frequency of 50.00 Hz and the response outside the dead band shall be with respect to a total change in frequency.

(3) shall have frequency controller with a settable droop of 1 to 6% of ICR. The inherent dead band of the of the frequency shall not exceed (+/-) 0.03 Hz:

....

Energy Storage System (ESS)

89. The requirements applicable to ESS are as specified in Table 4 below:

Table 4. Requirements for ESS

Fixed Speed PSP	Regulation 21 to 44
BESS	Regulation 45 to 88
Variable Speed PSP	Regulation 21 to 23, 32 to 44, 49 to 55 and 62

”

As per above, in the draft CEA Regulations it has been proposed to incorporate the droop setting for Pumped Storage Plant as well as BESS.

12.6 In view of the above, the droop settings for ESS as proposed by NLDC are proposed to be incorporated in the Regulations.

12.7 With regard to the Primary response requirement in respect of pumped storage plant and ESS, we agree with the proposal given by the NLDC and also observe that the draft Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2026 provide as under:

“36. The primary response requirement shall be as mentioned in Table 1 below:

Table 1. Primary response requirements	
Type	Response range
Coal, Lignite & Gas based thermal generating unit	(+/-) 5% of MCR
Hydro generating unit and On-stream PSP unit	(+/-) 10% of MCR (subject to rated head being available)
Off-stream PSP unit	(+/-) 10% of MCR (subject to rated head being available) for short duration

.....

76. The primary response requirement shall be as mentioned in Table 3 below:

Table 3. Primary response requirements	
Type	Response range
Solar, Wind and Battery Energy Storage System (BESS)	(+/-) 10% of ICR

As per the above, the CEA has also proposed to include the primary response requirement for Pumped Storage Plant (PSP) and Battery Energy Storage (BESS) in the draft Regulations.

12.8 In view of the suggestions of NLDC, the primary response requirement for Pumped Storage Plant and Energy Storage System (excluding Pumped Storage Plant) is proposed to be incorporated in the Grid Code. The Minimum Unit size for the said sources has been considered as suggested by NLDC. However, the Primary Response Capability shall be as per the CEA Technical Standards for Connectivity.

13. Amendment to Regulation 30(11) and Annexure-3: Revised methodology for estimation of reserves

13.1 Regulation 30(11)(k) of the Principal Regulations provides as under:

“(k)With due regard to the requirement of planning reserve margin and resource adequacy referred to in Chapter 2 of these regulations and based on the following methodologies, the secondary reserve capacity requirements shall be estimated by RLDCs for their respective regional control areas:

The positive and negative secondary reserve capacity requirements for any control area for a calendar year shall be equal to the 99 percentile of positive and negative ACE respectively of that control area during the previous financial year (Detailed Procedure shall be as per Annexure-3 to these regulations, which may be reviewed as and when considered necessary),

OR

The secondary reserve capacity requirement for any control area shall be equal to the 110 % of the largest unit size in the respective regional control area or state control area plus load forecast error plus wind forecast error plus solar forecast error during the previous calendar year.

OR

Such other methodology as may be stipulated by NLDC after obtaining the due approval of the Commission.”

As per the above, the Reserves shall be estimated as per the methodology stipulated by NLDC, after obtaining the Commission's due approval.

13.2 As per the above-quoted provisions of the Principal Regulations, NLDC has prepared a “Detailed Procedure for Assessment of Quantum of Secondary & Tertiary Reserve Capacity, along with Information Exchange and Timelines” which has been approved by the Commission vide Order dated 28th September, 2023. The relevant extracts of the said procedure are as under:

“Secondary Reserves

8.5 The estimation of secondary reserve capacity requirement, on regional basis and state basis (considering diversity benefit), shall be carried out by Nodal Agency as per the following methodology:

8.5.1 The positive (Up Reserve) and negative (Down Reserve) secondary reserve capacity requirement on regional basis would be computed as 99 percentile of negative and positive ACE respectively of that region for year ahead, quarter ahead and week ahead.

8.5.2 The 99 percentile of the positive and negative ACE of each state control shall be computed and aggregated at regional level. This shall be scaled using 99 percentiles of the regional ACE to factor diversity at regional level. The scaled values of 99 percentile of the state ACE shall be used to arrive at the reserve requirement at Inter-state and Intra-state levels.

8.5.3 The drawl by the respective state and its internal-generation at the time of peak demand during the period under consideration shall be used for apportionment of the reserve requirement. The intra state reserves shall be in proportion to the contribution of internal generation at the time peak demand.

The Inter-state reserves shall be in proportion to the drawl from the grid at the time of peak demand.

8.5.4 The state level requirement shall be aggregated to arrive at the regional and all India reserve requirement.

8.5.5 If any state control area has net injection in the concerned period, then, entire reserve calculated for such State, is to be allocated within the state control area.

8.5.6 If any state control area has zero internal generation in the concerned period, then, the required reserve is to be allocated at the regional level. 8.6 The all-India total of positive (and negative) secondary reserves capacity requirement on regional basis shall be equal to the reference contingency or secondary reserve capacity requirement as computed above, whichever is higher. If the all-India reserve requirement, computed using 99 percentile of ACE, is less than the reference contingency such additional reserves shall be considered in the regional requirement.”

Tertiary Reserves

8.7 The estimated quantum of tertiary reserve requirement at regional level would be considered equal to the secondary reserve requirement at regional level as computed above.

8.8 The estimated quantum of tertiary reserve requirement at state level would be considered equal to the sum of secondary reserve requirement at state level and 50 % of the largest unit size in the respective state control area.”

As per the above, the quantum of secondary and tertiary reserves is determined.

13.3 The relevant extracts of the Order dated 05.10.2025 in 9/SM/2025 are as under:

“6. Conclusion and way forward:

....

6.4 Reserve estimation and management Most of the states are not maintaining reserves allocated by the NLDC to the respective States as per the provisions of the Grid Code. Further, the NER states highlighted that the reserve requirement is on higher side as compared to their peak demand. NLDC is currently maintaining reserves with the cost being socialized among all states through DSM. However, from next year onwards, it has been provided that the cost may be directly allocated to States in ratio of shortfall in maintaining the reserves by them, which may be costly. States must plan accordingly to avoid high-cost allocations and they should review their future generation capacity or long-term tie-ups to ensure availability of adequate power and reserves. DVC SLDC pointed out an issue which needs to be considered. DVC stated that as per understanding the contracted capacity meant for maintaining Reserve should not be scheduled except under contingency or extreme conditions. However, as per the provisions under LPSC Rules, a generator needs to offer the surrendered power of any DISCOM in the Day Ahead Market. Thus, the Day-ahead surrendered power of any DISCOM may not be available because of sale of the power by the Generator in Day Ahead Market. It was discussed that under the Grid Code 2023, the state wise quantum of reserves is required to be reassessed for three day ahead and day ahead basis which should be published by NLDC as per provisions of the Grid Code. Some States pointed out that there are no regulations on AGC in the State.

State SLDCs lack clarity on reserve estimation and allocation, accordingly the respective RLDCs in coordination with NLDC needs to held discussion with the SLDCs to explain the exact process of reserve estimation and allocation of reserve quantum of each state and RLDCs may also share the required tools with SLDCs.

Further, a specific portion of the generation should be earmarked exclusively as a reserve and that reserve quantum should not be scheduled unless there is contingency. The commercial issues if any with regard to maintaining the reserves, needs to be looked into by the respective State Electricity Regulatory Commission.

Way Forward:

- (i) SLDCs to take up the issue of maintaining the reserves with their respective Discoms to maintain the reserves as allocated to them by NLDC as per the provisions of the Grid Code.*
- (ii) RLDCs to hold discussions with respective SLDCs, in coordination with NLDC to explain the exact process of estimation and allocation of reserve quantum of each state.*
- (iii) NLDC to review the quantum of reserves allocated to North-Eastern Region states, where the reserve requirement appears disproportionately high compared to their demand.*
- (iv) The regulations enabling implementation of AGC and recovery of cost of maintaining reserves may be taken up at FOR level on recommendations and requirements cited by States.”*

As per the above, it was suggested that NLDC to review the quantum of reserves allocated to North-Eastern Region states, where the reserve requirement appears disproportionately high when compared to their demand.

13.4 NLDC vide its letter dated 05.03.2026 submitted an approach paper for review of Reserve Estimation Methodology. The summary of suggestions as per the said approach paper are as under:

- “1. Adopt 95th percentile ACE based reserve estimation for initial implementation, with a transition to 99th percentile as data quality, system maturity, and operational experience improve.*
- 2. Introduce quarter ahead reserve estimation to account for seasonal variability in ACE and demand patterns. Continue year-ahead, three day-ahead, and day-ahead reserve assessments using refined methodologies.*
- 3. Discontinue inclusion of 50% of the largest unit size for intra-state down tertiary reserves for all States. Exempt States with largest unit size <500 MW from the requirement of maintaining 50% of the largest unit size for intra-state up tertiary reserves.*
- 4. Introduce explicit regulatory provisions by SERCs for allowing advance procurement of Up and Down Reserves by the SLDCs.*
- 5. Require States to procure reserves in advance and avoid dependence on the Real Time Market (RTM) for balancing reserves.*
- 6. Ensure earmarked reserves are not used for routine scheduling and remain available post gate-closure for SLDC dispatch. Recognize capacity earmarked for SRAS/TRAS, and capacity offered in day-ahead and real-time ancillary markets, as eligible for fulfilment of reserve obligation.*
- 7. Need for a comprehensive reserve quantification, estimation, and monitoring framework. Implement real-time reserve monitoring through SCADA/IT telemetry.*
- 8. Streamline gate-closure timelines at state and regional levels for efficient reserve dispatch.*

9. States may maintain resource adequacy including reserves through internal generation and advance market procurement. Enable cost recovery for reserve maintenance through approval by concerned SERCs. Need for a payment mechanism approved by SERCs for reserves earmarked by SLDCs.

10. Extend reserve obligations to ISTS-connected bulk consumers, proportionate to their contribution to ACE/deviations.

11. In order to implement the provisions of Regulation 9(7)(ii) of the CERC DSM Regulations, 2024, appropriate mechanisms for quantification, measurement, dispatch, and settlement of reserves may be required to be established.

12. States may be mandated to maintain reserves as part of their daily intra-state resource scheduling programmes.”

As per the above, the NLDC has mainly suggested adopting 95th percentile ACE-based reserve estimation, introduction of quarter-ahead reserve estimation, exemption of States with largest unit size of <500 MW from the requirement of maintaining 50% of the largest unit size for intra-state up to tertiary reserves, and extending the reserve obligation to ISTS-connected bulk consumers.

13.5 In view of the suggestions of NLDC, reserve obligations to regional entity bulk consumers and estimation of reserves on a quarter-ahead basis are proposed to be incorporated in the Regulations and accordingly an amendment is proposed under sub-clauses (k), (p), (q) and (t) of regulation 30(11) and Annexure-3.

13.6 Since the Principal Regulations already provide for framing a methodology for estimation of reserves by NLDC with the approval of the Commission, it is clarified that the NLDC may revise the existing procedure, adopting a percentile other than the 99th percentile and incorporating other suggestions as per its approach paper and submit the same to the Commission for approval after stakeholders' consultation.

14. Incorporation of congestion charge provisions under the Grid Code and repeal of CERC (Measures to relieve congestion in real time operation) Regulations, 2009.

14.1 CERC (Measures to relieve congestion in real time operation) Regulations, 2009 were notified on 22nd December 2009, which provide that, to relieve congestion in real time, a congestion charge shall be applied as a commercial measure. The congestion charge is payable by a Regional entity causing congestion in the inter-regional link or intra-regional link and receivable by a Regional entity or entities relieving congestion.

14.2 Since the application of congestion charges is a commercial measure so as to ensure grid security, the provision regarding congestion charge is proposed to be incorporated under the Grid Code as a new Regulation 30A.

14.3 WRPC vide letter dated 23.12.2025 submitted as under:

“NLDC vide Notice No. NLDC/2025/08/19 dated 19.08.2025 (Copy enclosed as Annexure-1) has intimated that congestion occurred during the period from 12:46 hrs to 15:45 hrs (Block 64) from the Southern Region to the Western Region (import from the Southern Region), & during the period from 12:46 hrs to 16:15 hrs (Block 66) from the Western Region to the Northern Region (export to the Northern Region) on 19.08.2025 and the congestion charges would apply to all the WR entities deviating from schedules.

2. The Regulation (4) of Hon'ble CERC (Measures to relieve congestion in real-time operation) Regulations, 2009 is reproduced below:

1) To relieve congestion in the real time, a congestion charge shall be applied as a commercial measure. The congestion charge will be payable by a Regional entity or entities causing congestion in the inter-regional link or intra-regional link and receivable by a Regional entity or entities relieving congestion.

2) Congestion charge may be imposed on any Regional entity or entities in any Region or Regions for causing congestion and paid to any Regional entity or entities in any Region or Regions for relieving congestion as per the detailed procedure under these regulations formulated by NLDC and approved by the Commission.

3. Further, as per the Detailed Procedure for Relieving Congestion in Real-Time Operation dated 22nd April 2013 issued under Regulation 4(2) of the CERC (Measures to Relieve Congestion in Real-Time Operation) Regulations, 2009, the relevant provision of application of congestion charges as given below:

6.2. Congestion charge would be levied for

- a) over drawal or under-injection in the importing control area and*
- b) under drawal or over-injection in the exporting control area*

4. As can be seen from the notice of NLDC dated 19.08.2025, a simultaneous congestion between SR-WR (WR as importing region) and WR-NR (WR as exporting region) occurred on 19.08.2025 during the period 12:46 hrs to 15:45 hrs, and there was heavy export from SR & heavy import by NR through WR (wheeling region). The methodology for the application of congestion charges under such a scenario has not been dealt with in the regulations & procedures given under para 2 & para 3, respectively.

5. The matter was discussed in the 95th Commercial sub-Committee Meeting of WRPC held on 21.11.2025 in which it transpired that the approach for application of congestion charges to all WR entities deviating from schedules, as mentioned in the notice of NLDC, may not be in consonance with the spirit of the Regulations. It was decided that the congestion statements shall be issued by treating the congestion on the SR-WR corridor and the WR- NR corridor as two separate congestion cases, until a specific order is issued by

the Hon'ble CERC prescribing the methodology for computation of congestion charges of wheeling region (WR in this case) under such scenario.”

14.4 As per the above, the WRPC has highlighted that the methodology for the application of congestion charges under the condition of a simultaneous congestion between two corridors is not provided under the regulations or the procedure.

14.5 NLDC vide letter dated 26.12.2025 submitted revised draft procedure for Relieving Congestion in Real Time Operation, incorporating methodology for invoking congestion charge to wheeling region in case of simultaneous congestion in import and export region for approval of the Commission. The relevant extract of the draft procedure is as under:

“iii. Congestion charge to wheeling region in case of simultaneous congestion in import and export –

a) Where a control area/region simultaneously acts as both an importing control area (downstream) with respect to one congested corridor and an exporting control area (upstream) with respect to another congested corridor (i.e. the control area/region is wheeling power and both its incoming and outgoing corridors are congested at the same time), any deviation from schedule by regional entities in that control area/region shall attract congestion charge irrespective of the direction or nature of the deviation and irrespective of whether the deviation apparently relieves or aggravates the congestion on a particular corridor.

Provided that the deviation from schedule is more than ± 20 MW in the particular time block when congestion charge is invoked.

.....”

14.6 In view of the above, a provision for a congestion charge to entities in the wheeling region in case of simultaneous congestion in both import and export regions is also proposed to be incorporated.

14.7 With the incorporation of provisions regarding congestion charge in the Grid Code and the effectiveness of the CERC (Indian Electricity Grid Code) (Second Amendment) Regulations, 2026, CERC (Measures to relieve congestion in real time operation) Regulations, 2009 shall stand repealed. Accordingly, a new Clause (5) is also proposed to be inserted under Regulation 59 of the Principal Regulations.

14.8 Further, as per the proposed amendment, the rate of congestion charge is to be separately specified by the Commission under the Grid Code, and a detailed procedure for levy of congestion charge is to be prepared by NLDC, which may take some time. Accordingly, it is provided that, till the rate of congestion charge

is notified by the Commission under the Grid Code, the rate of congestion charge and Detailed Procedure for relieving congestion in real time operation, already in force under the Central Electricity Regulatory Commission (Measures to relieve congestion in real time operation) Regulations, 2009 shall continue to be in operation. New Clause (6) and (7) are proposed to be inserted under Regulation 59 of the Principal Regulations accordingly.

14.9 The Definition of “Congestion Charge” is also proposed to be incorporated in Regulation 3 of the Principal Regulations.

15. Amendment to Regulation 45: Revision of high inflow period for hydro power plants

15.1 NHPC, vide its email dated 19.07.2024, submitted as under:

“As per the above-mentioned clauses, hydro generating stations are allowed to declare DC up to 110% of normative ex-bus capacity, only during the high inflow periods specified by respective RPC. However, it has been observed that high inflow period declared by RPC does not necessarily coincide with the actual high inflow period in a year. For instance, high inflow period declared by RPC for FY 2024-25 is June to September, but high inflow was observed in month of May 24 also.

Hence in view of optimum utilization of the hydro resources and to avoid spillage, it is requested that hydro stations may be allowed to declare DC up to 110% of normative ex-bus capacity whenever there is high inflow which may be beyond the RPC declared high inflow period.”

As per the above, NHPC has pointed out that the high inflow periods declared by RPCs do not coincide with the actual high inflow period; hence, NHPC has requested to allow declaring the higher DC whenever there is high inflow beyond the RPC-declared high inflow period.

15.2 Clause 8 of Regulation 45 of the Principal Regulations provides as under:

“(8) Declaration of Declared Capacity by Regional entity generating stations

(a) The regional entity generating station other than the WS seller shall declare ex-bus Declared Capacity limited to 100% MCR less auxiliary power consumption, on day ahead basis as per the provisions of Regulation 49 of these regulations:

Provided that the hydro generating stations may declare ex-bus Declared Capacity more than 100% MCR less auxiliary power consumption limited to overload capability in terms of sub-clause (a) of clause (10) of this Regulation during high inflow periods:

Provide further that a high inflow period for this purpose shall be notified by the respective RPC.”

15.3 Clause 10 of Regulation 45 of the Principal Regulations provides as under:

“(10) Optimum Utilization of Hydro Energy:

(a) During high inflow and water spillage conditions, for Storage type generating station and Run-of-River Generating Stations with or without Pondage, the declared capacity for the day may be up to the installed capacity plus overload capability (up to 10% or such other limit as certified by the OEM and approved by CEA) minus auxiliary consumption, corrected for the reservoir level. In case, the overload capability of such a station is more than 10% as approved, such a station shall declare the overload capability in advance.

(b) During high inflow and water spillage conditions, the concerned RLDC shall allow scheduling of power from hydro generating stations for overload capability up to 10% of Installed Capacity or any other limit as per sub-clause (a) of this clause without the requirement of additional GNA for such overload capacity, subject to the availability of margins in the transmission system.”

15.4 As per the above provisions, a hydro generating station may declare the declared capacity up to the installed capacity plus overload capability (up to 10% or such other limit as certified by the OEM and approved by CEA) minus auxiliary consumption during high inflow periods and the high inflow period for this purpose is notified by the respective RPC.

15.5 The relevant extracts of the 53rd meeting of the Commercial Sub-committee of NRPC held on 19.12.2025 are as under:

“AA2 Declaration of High Flow Season for calendar year 2026 (Agenda by NRPC Secretariat)

1. Regulation 45.8(a) of the CERC (IEGC) Regulations, 2023, effective from 01.10.2023, permits hydro generating stations to declare ex-bus Declared Capacity beyond 100% MCR less auxiliary power consumption limited to overload capability during notified high inflow periods.

2. Regulation 12.1(a) of the CERC (Sharing of ISTS Charges and Losses) Regulations provides that an overload capacity of 10% during the peak season shall be considered by RPCs for calculation of transmission deviation of hydro generating stations.

3. Accordingly, based on the previously declared high flow season for Regional Hydro Generators of NR for the year 2025, following high flow season for the year 2026 was proposed by NRPC secretariat:

S. No.	Hydro Generating Station	Developer	State	Proposed High inflow season for calendar year 2026	Status
1	AD Hydro	ADHPL	Himachal Pradesh	16th May to 15th September	Confirmed by utility
2	Bairasiul	NHPC	Himachal Pradesh	May to August	Confirmed by utility
3	Chamera-I	NHPC	Himachal Pradesh	May to August	Confirmed by utility
4	Chamera-II	NHPC	Himachal Pradesh	May to August	Confirmed by utility
5	Chamera-III	NHPC	Himachal Pradesh	May to August	Confirmed by utility
6	Dhauliganga	NHPC	Uttarakhand	June to September	Confirmed by utility
7	Dulhasti	NHPC	Jammu & Kashmir	16th May to 15th September	Confirmed by utility
8	Greenko Budhil	GREENKO BUDHIL	Himachal Pradesh	June to September	Confirmation Pending
9	Karcham Wangtoo	JSW HEL	Himachal Pradesh	June to September	Confirmation Pending
10	Kishanganga	NHPC	Jammu & Kashmir	16th April to 15th August	Confirmed by utility
11	Koldam	NTPC	Himachal Pradesh	June to September	Confirmation Pending
12	Koteshwar	THDC	Uttarakhand	September to December	Confirmed by utility
13	Nathpa Jhakri	SJVNL	Himachal	June to September	Confirmation

....

Decision of the Forum:

4. Regional Hydro Generating Stations for which confirmation has been received from the concerned utilities on the high flow season proposed by the Secretariat may be treated as declared. In respect of stations where confirmation is still pending, the High Flow Season as proposed in the meeting may be considered on a tentative basis. Such generators may be requested to confirm their respective High Flow Season at the earliest, and in case any change is proposed, supporting data for the past five years (from 2021 onwards) may be submitted. If no confirmation is received within the stipulated time, the High Flow Season as proposed will be deemed to have been declared.”

As per the above, it is observed that the RPC declares the high inflow period for the respective generating station based on the inputs from the concerned utility.

15.6 On the issue highlighted by the NHPC, we are of the view that there may be some variations in the already declared high inflow season by the RPC. Therefore, the concerned utility may take up the issue with the respective RPC if there is anticipation by the utility that there may be variations in the already declared period and, accordingly, the concerned RPC may, on the input of the concerned utility, revise the already declared high inflow period for such utility before the commencement of the already declared high inflow period. Accordingly, the amendment is proposed.

16. New Regulation 45 (16): Regulation of access to defaulting entities that have defaulted in payment of various statutory dues payable under the CERC Regulations.

16.1 Regulation 33 of the CERC (Fees and Charges of Regional Load Despatch Centre and other related matters) Regulations, 2024, provides as under:

“33. Regulation of access to defaulting entities:

(1) In case of non-payment of dues by the users or in case of non-maintenance of payment security mechanism after the default trigger date, the scheduling of electricity for the defaulting entity shall be regulated as follows:

(a) T-GNA, including already approved T-GNA, for the sale and purchase of electricity through short term contracts, including in the power exchange, shall be regulated entirely:

Provided further that the NLDC may, under exceptional circumstances for grid security, temporarily review the regulation of T-GNA and record the reasons for doing so in writing.

(b) If, even one month after the regulation of the T-GNA, the dues remain unpaid, apart from the regulation of the short term contracts under T-

GNA in its entirety, the short term contracts under GNA shall be regulated entirely.

(c) The reduction or withdrawal of access for sale and purchase of electricity through contracts other than short-term contracts shall be in such a manner that the quantum of reduction in drawl or injection schedule increases progressively by ten per cent (10%) for each month of default.

(2) In case of default by the transmission licensee, on intimation by RLDC, after the default trigger date, CTU shall transfer the due amount for RLDC from the amount recovered from drawee DICs towards yearly transmission charges for such defaulting ISTS transmission licensee within 7 days from the date of issuance of such intimation by RLDC.

(3) Upon payment of outstanding dues or maintaining adequate Payment Security Mechanism, as the case may be, the regulation of access shall cease to operate, and access shall be restored at the earliest, but not later than one day, excluding the day on which payment is made.”

16.2 As per the above, the Fee and Charges of Regional Load Despatch Centre and other related matters Regulations provide for Regulation of access of the defaulting entities which default in payment of dues as per the said Regulations.

16.3 We observe that there are various statutory charges which are payable by the generating stations or drawee entities under various regulations of CERC, such as DSM charges, Congestion charges and reactive energy charges. The default in payment by the entity that has to pay such charges results in a deficit of the Pool Account and consequently delayed payment to the receiving entity.

16.4 Therefore, similar provisions as provided under Fee and Charges Regulations are proposed to be incorporated as a new Clause (16) in Regulation 45 of the Principal Regulations for regulation of scheduling of electricity of an entity in case of default in payment of various statutory charges payable under the CERC Regulations or non-maintenance of payment security mechanism as per the applicable regulations.

16.5 In view of the above proposed amendment, a new definition of “Default trigger date” is proposed to be inserted under Regulation 3 at Serial No. 35a.

17. New Regulation 45 (17): Scheduling of Free Power share of State Govt. from bus bar of Central Hydro Generating Station

17.1 The Electricity (Removal of Difficulty) Third Order, 2005, dated 08.06.2005, provides as under:

"The State Government Receiving free electricity from hydro generating Stations shall have discretion to dispose of such electricity in the manner it deems fit according to the provisions of the Act:"

As per the above, the State Government can sell its free power share in the hydro generating stations as per the Electricity (Removal of difficulty) Third Order, 2005, dated 08.06.2005

17.2 GoHP found it difficult to sell its share of free power in Central Hydro Generating Stations, without it being scheduled for drawl by HPSEBL i.e. Himachal Discom.

17.3 Directorate of Energy (DOE), Govt. of HP (GoHP) had submitted that GoHP has an entitled share of free power in various Central Generating Stations (CGS) (Hydro) situated in Himachal Pradesh, and this share of free power is managed by the DoE, GOHP through various avenues of sale such as Power Exchanges and Bilateral mode. Further, as per NRPC allocation orders, the share of free power available from these plants is scheduled to Himachal Pradesh and then sold by DoE, GoHP through its trader at the platform of Power Exchanges/ Bilateral mode. However, under the Grid Code, Himachal Pradesh is entitled to schedule power from Inter-State Generating Stations (ISGS) up to the GNA quantum, i.e., 1130 MW. The allocated power to HPSEBL (State Discom) from ISGS plants and other arrangements is around 1200 to 1400 MW, excluding GoHP free power. GoHP finds it difficult to sell its share of free power in CGS, which is 557 MW; without it being scheduled as drawal by HPSEB.

17.4 The Commission considered the difficulties expressed by GoHP in Suo-moto Petition No. 18/SM/2023. The relevant extract of the Order dated 18.12.2023 in Suo-moto Petition No. 18/SM/2023 is as under:

"24. We have considered the suggestions of Govt of HP. We observe that prior to the Grid Code coming into effect i.e. till 30.09.2023, the power from ISGS hydro generating stations was scheduled to HPSEB at HP State periphery and from HP State periphery, Govt of HP sold its share of free power. In case of revision of DC and schedule of such generating stations, the entitlement of free power at HPSEB periphery also changes for the Govt of HP.

25. We further observe that Govt of HP is not a drawee entity. It is entitled to the free power which it can sell as per the Electricity (Removal of difficulty) Third order 2005 dated 08.06.2005. We find that Govt of HP is a unique case of an entity which is neither a generator nor a trader buying electricity for sale. It would not draw power but would always have free power for sale.

26. Considering the suggestions and the peculiar circumstances of the Govt of HP, and the fact that Govt of HP cannot directly consume the power, we are of the considered view that Govt of HP or a similar such Govts. of hydro-rich states may sell their entitled share of free power directly from the bus bar of the generating station. We note that there may be some issues with respect to DSM accounting for such generating station and sale of power by the Govt of HP since DSM shall be calculated for the generating station but shall be required to be segregated between the DSM payable/receivable by the generating station and the Govt. selling free power. Accordingly, we direct NLDC to prepare a Procedure to facilitate such accounting in consultation with RLDC, RPC, generating station and the entity to whom such free power has been allocated within a month of the issue of this Order and submit it to the Commission for approval.”

17.5 As per above, considering the case of the Government of Himachal Pradesh, the Commission directed NLDC to prepare a Procedure for scheduling of free power share in the Central Generating Stations to facilitate DSM accounting, in consultation with RLDC, RPC, generating station and the entity to whom such free power has been allocated and submit it to the Commission for approval.

17.6 NLDC. vide its letter dated 13.02.2024, had submitted the “Procedure for Scheduling and Accounting of Deviation Settlement Mechanism Charges for Ex-bus sale of free power by Government of Himachal Pradesh” after stakeholder consultation, for approval of the Commission.

17.7 The Commission examined the Detailed Procedure and, vide letter dated 03.08.2024, intimated to the NLDC as under:

“This is in reference to your letter No. Grid-India/NLDC/2023 dated 13.02.2024, vide which a Procedure to facilitate scheduling and accounting of Free Power from bus bar of generating station by the State Government was submitted for approval of the Commission in line with Suo-moto Order dated 18.12.2023 in Petition No. 18/SM/2023. The Procedure as submitted by the NLDC has been examined. It is observed that the Procedure as submitted by the NLDC has been framed for scheduling and accounting of the sale of free power in respect of GoHP only. Further, NLDC has done consultation on the subject procedure with NRLDC, NRPC, GoHP, HPSEBL, NTPC, and NHPC.

.....

3. As per the above order, a generic Procedure was required to be made to facilitate the scheduling and accounting of free power for the Government of hydro-rich states which have free power share in Central Hydro Generating Stations. The same was required to be made with wider Public consultation. The procedure has been accordingly modified to make it a generic procedure and to incorporate changes as required in line with Order in 18/SM/2023 and the modified Procedure is enclosed as Annexure-A.

4. It is requested that a wider Public consultation on the attached Procedure be carried out by uploading it to NLDC website and thereafter the revised Procedure after incorporating the comments received from the stakeholders along with the comments

received and their treatment thereof, be submitted to the Commission for approval within a period of sixty days from the issuance of this letter.

5. Keeping in view the difficulties expressed by HPSEB during high hydro season, the attached procedure shall be implemented for Himachal Pradesh at the earliest but not later than 09.08.2024, as an interim measure for the current high hydro season.”

As per the above, NLDC was intimated that a generic procedure is required to facilitate the scheduling and accounting of free power for the Government of hydro-rich states that have a free power share in Central Hydro Generating Station and the same was required to be made with wider public consultation. Accordingly, the draft procedure submitted by NLDC, vide its letter dated 13.02.2024, with suitable changes, was sent to NLDC for wider public consultation by uploading it on the NLDC website and thereafter submitting it after incorporating the comments received for approval of the Commission. However, in view of the difficulties expressed by HPSEB during high hydro season, the said procedure has been implemented for Himachal Pradesh as an interim measure.

17.8 Subsequently, NLDC, vide its letter dated 11.03.2025, has submitted the “Procedure to facilitate scheduling and accounting of Free Power share of State Govt. from bus bar of Central Hydro Generating Station” after stakeholder consultation, for approval of the Commission along with the comments received from the Stakeholders.

17.9 As the scheduling of Power is governed as per the provisions of the Grid Code, accordingly, the provisions regarding scheduling of free power share of State Govt. from bus bar of Central Hydro Generating Stations are proposed to be incorporated under Regulation 45 of the Principal Regulation as a new Clause (17), and the procedure is proposed to be incorporated as a new Annexure-8.

17.10 Further, in view of the above proposed amendment, a new definition of “Central Hydro Generating Station” or “CHGS” is proposed to be inserted in Regulation 3 at Serial No. 22a.

18. Amendment to Regulation 48 (3)(f): Supply of power from alternate sources in case of generating stations other than 62 with the express consent of the buyer and mutual agreement on sharing of net savings (in case of no contract).

18.1 Regulation 48(3)(f) of the Principal Regulations provides as under:

“48. SCHEDULING FROM ALTERNATE SOURCE OF POWER BY A GENERATING STATION

(1) A generating station may supply power from alternate source in case of (i) USD in terms of clause (1) of Regulation 47 of these regulations or (ii) forced outage of unit(s) or (iii) a generating station other than REGS replacing its scheduled generation by power supplied from REGS irrespective of whether such identified sources are located within or outside the premises of the generating station or at a different location.

.....

(3) The methodology for scheduling of power from alternate sources covered under sub clause (iii) of clause (1) of this regulation, shall be as per the following steps:

.....

(f) In case of a generating station other than whose tariff is determined by the Commission under Section 62 of the Act, supply of power by such generating station to its buyer from an alternate source in terms of sub-clauses (a) to (d) of this clause shall be in accordance with the contract with the buyer and in the absence of a specific provision in the contract, in terms of mutual consent including on sharing of net savings between the generating station and the buyer.

18.2 As per the above, the generating stations other than those whose tariff is determined by the Commission under Section 62 of the Act, may supply power to their buyer from an alternate source in terms of mutual consent, including on sharing of net savings between the generating station and the buyer, in the absence of provisions in the Contract.

18.3 NLDC, vide e-mail dated 29.08.2025 gave feedback on implementation of the abovesaid clause, wherein it came out that a clarity may be required regarding seeking consent of beneficiaries such that beneficiaries are aware of such replacement and is shared the savings.

18.4 In view of the above, it is proposed that supply of power from alternate sources in case of generating stations other than 62 shall be as per the contract and, in case of no contract, only with the express consent of the buyer and mutual agreement on sharing of net savings. Accordingly, sub-clause (f) of Clause (3) of Regulation 48 of the Principal Regulations is proposed to be amended.

19. Other Amendments:

19.1 Clause (2) of Annexure-3 with respect to accounting and payment of reactive energy charges provides that the concerned regional entities shall pay the amounts into the regional Pool Account operated by the RLDC within 10 (ten) days of issue of statement for Var charges by RPC, and the regional entities who have to receive the money on account of VAR charges would then be paid out from the regional Pool Account, within two (2) working days from the receipt of payment in the Pool Account. If payments against the VAR charges are delayed by more than

two days, i.e., beyond twelve (12) days from the issue of the statement by RPC Secretariat, the defaulting regional entity shall pay simple interest @ 0.04% for each day of delay.

As per the above, interest is charged to the defaulting entity from the 13th day, while the due date of payment is 10 days from the issuance of account by RPC.

Grid India vide draft detailed procedure submitted vide letter dated 15.09.2025 suggested to modify the provisions of various statutory charges and make them uniform for ease of implementation wherein it suggested to take interest from due date. Accordingly, it is proposed that if payments against the VAR charges are delayed beyond the due date, the defaulting regional entity shall pay simple interest @ 0.04% for each day of delay. Accordingly, the amendment has been proposed in sub-clause (d) of Clause (2) of Annexure-4 of Principal Regulations.

19.2 A definition of “Renewable Energy Implementing Agency” or “REIA” has been proposed to be incorporated for clarity, as the term REIA has been used in the proposed amendment.

20. Amendment to Regulation 48 and 49: RTM Gate Closure timelines

A. Procedure for scheduling of Transactions in Real Time Market

20.1 The Real Time Market (RTM) was introduced in June 2020 as a half-hourly market to enable load-generation balancing closer to real time, providing an avenue for balancing the demand-supply positions of Discoms and Gencos, closer to actual delivery of the power through an organised market platform. Under the existing timeline for Real Time Market, buy and sell bids are placed for a half-hour delivery period, and the Power Exchanges currently conduct 48 RTM sessions per day.

20.2 Gate closure refers to the time at which the bidding for a specific delivery period closes, and no further bidding or modification of already placed bids can take place for the said delivery period. The Gate closure for the Real Time Market (RTM) currently occurs 60 minutes before the start of the delivery time block. After the RTM gate closes, the system operator assumes responsibility for balancing the system. The current 60-minute timeline was set when RTM was introduced in 2020, based on the operational constraints then highlighted by the System Operator. Figure 1 shows the existing RTM timeline, while Figure 2 shows the timeline for two successive RTM sessions.

20.3 The Commission, while introducing the RTM, had highlighted the need to shorten the time between the RTM auction and delivery of power for managing the real-time variations, including renewable generation in the system. The Commission also suggested that, with the required automation in place, the RTM would be brought closer to the actual delivery time.

Figure-1: Existing timeline for Real Time Market (RTM)

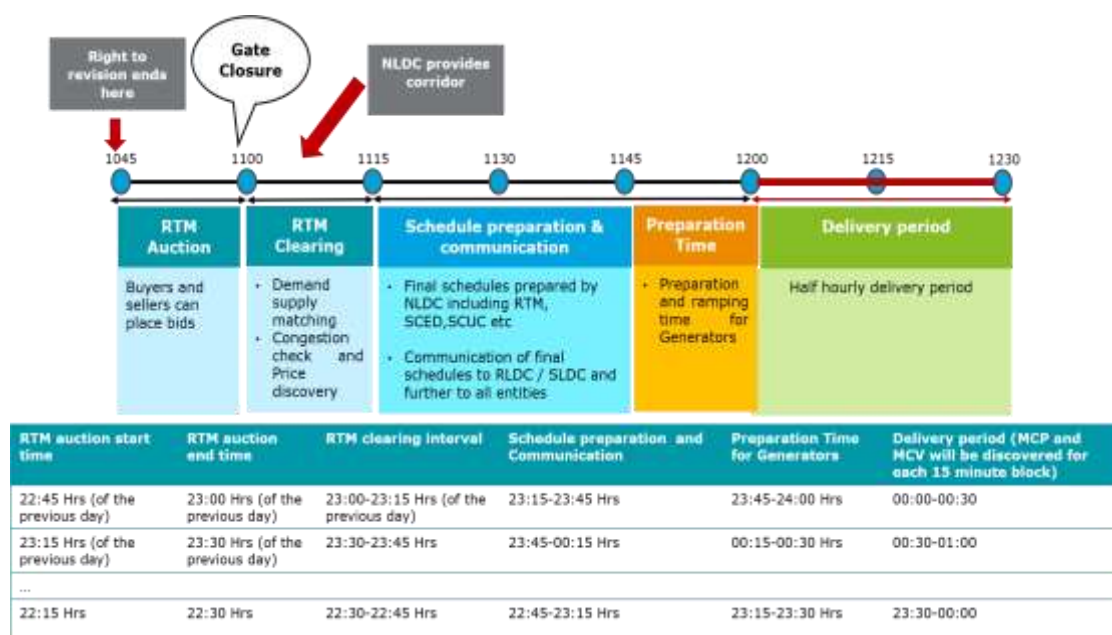
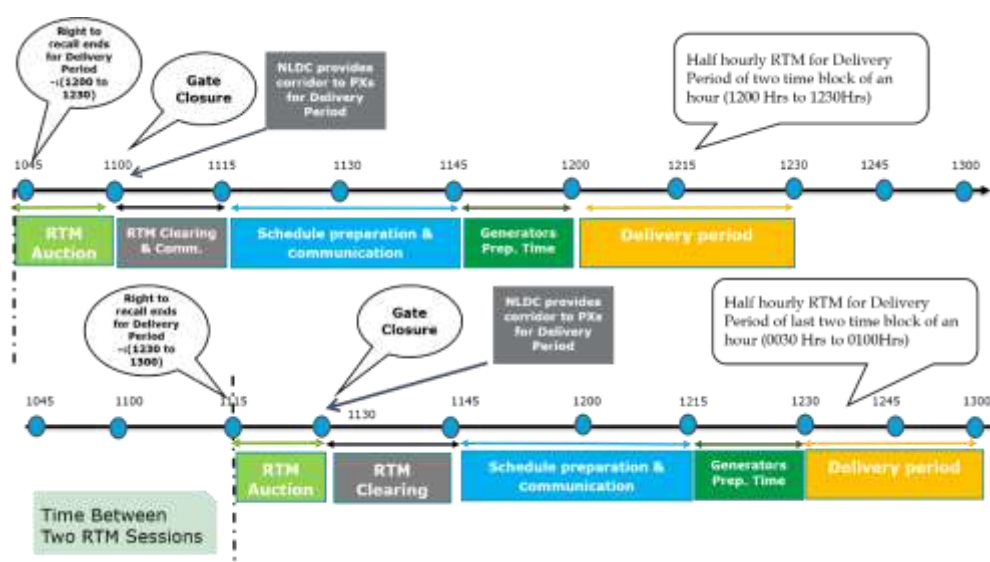


Figure-2: Existing Timelines for two successive RTM sessions



20.4 The Real Time Market (RTM) has been operational for over five years and, barring a few instances during the initial month of implementation, no RTM session

has been aborted. The requisite automation, including the National Open Access Registry (NOAR) and other technological advancements, is now in place to facilitate regular and timely information exchange between power exchanges and system operators. The sustained growth in RTM market volumes further reflects market participants' confidence and the effectiveness of existing mechanisms in ensuring adherence to RTM timelines.

20.5 Further, stakeholders have, on several occasions, highlighted that the time gap of more than one hour between gate closure and actual dispatch makes accurate demand forecasting challenging, leading to demand–supply mismatches and potential exposure to deviation charges under the Deviation Settlement Mechanism (DSM). DISCOMs have emphasised that electricity demand is dynamic and influenced by factors such as weather conditions, public holidays, social events, festivals, and supply disruptions. Similarly, RE generators face challenges in accurately forecasting and scheduling generation, which may result in DSM exposure, while curtailment of RE generation continues in certain cases due to grid constraints.

20.6 In view of the above, the feasibility of compressing the timelines for Real Time Market (RTM) was discussed with Grid-India, keeping in view the technological upgradations undertaken in the system. Based on these deliberations, a Staff Paper titled "Shortening the Scheduling Timeline for Real Time Market in India" was published on 06.05.2026, proposing a revised timeline for reducing the interval between the right to revision and the actual delivery of power from the existing 75 minutes to 50 minutes. The discussion paper proposed reducing the RTM bidding window from the existing 15 minutes to 5 minutes and reducing the time between RTM clearing and the delivery period from 45 minutes to 30 minutes, for the System Operator. Comments from the 35 stakeholders across different verticals of the Power Sector, such as Generators, Utilities, Institutions, and Associations, were received on the said Staff Paper by 28.05.2026.

20.7 The majority of the stakeholders welcomed the proposal to shorten the timeline. However, a few stakeholders urged retaining the bidding window at 10 minutes, on the grounds that a 5-minute bidding window would be inadequate to complete the sequential steps involved, as the WBES portal itself requires at least 3-4 minutes to reflect the revised schedule. Many stakeholders suggested ensuring

technological readiness, with adequate automation capabilities and infrastructure in place, to reduce bidding windows to 5 minutes instead of 15 minutes. Further, some stakeholders suggested implementing mandatory automation and standardised API-based integration across NLDCs, SLDCs, RLDCs, Power Exchanges, and WBES before shortening the timeline. Some stakeholders also supported further shortening the timeline to 4 time blocks before delivery of power, to allow RE generators to revise their schedules closer to delivery.

20.8 The Commission has considered the comments/suggestions received from the stakeholders on the above staff paper, and upon detailed deliberations, the Commission is of the view that the revised timeline needs to be implemented in a calibrated and phased manner, so as to provide adequate time to all the stakeholders for requisite automation before full-scale implementation. Accordingly, the Commission has decided to implement the shortened scheduling timeline in phases, as explained in the following paras.

Under Phase-1 (Till 31.03.2027): Shortening of the existing timeline by 15 minutes.

Phase-II (from 01.04.2027): Shortening of the existing timeline by 30 minutes.

20.9 **Under Phase-I (till 31.03.2027):** The Commission is proposing a reduction of 15 minutes (one-time block) between the clearing of an RTM session and commencement of the delivery period of the RTM session, while retaining the timeline for the RTM bidding and RTM clearing as 15 minutes (1 time-block) each. Accordingly, the System Operator would have 15 minutes instead of 30 minutes after clearing the RTM session to prepare and communicate schedules under RTM, SCED, SCUC, and TRAS dispatch. The detailed process sequence to be followed under Phase-I is depicted schematically in Fig. 3 below, and Fig. 4 provides a schematic of the timelines between two successive RTM sessions.

Figure-3: Phase-1 (up to 31.03.2027) timeline for Real Time Market

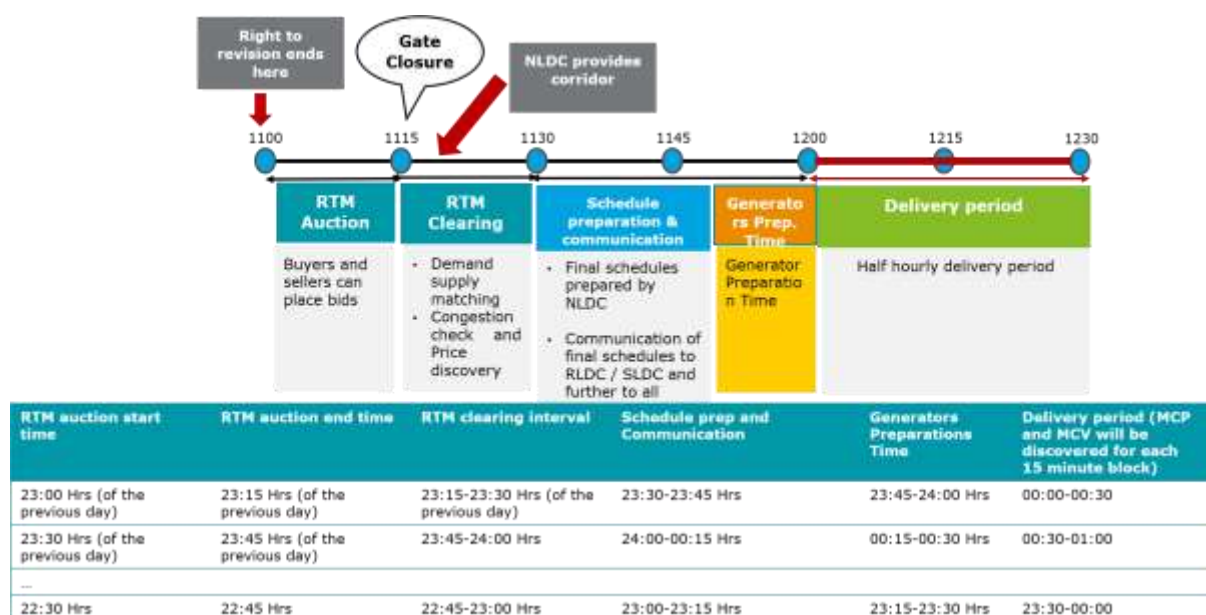
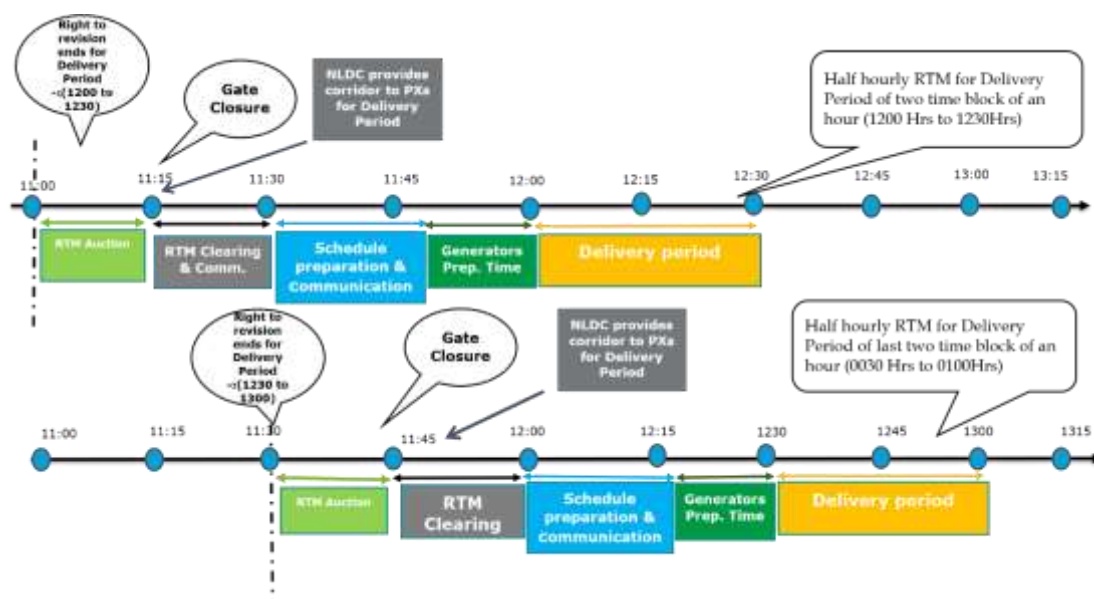


Figure-4: Phase 1 (up to 31.03.2027) - Timelines for two successive RTM sessions



20.10 The following table (Table-1) provides details of various activities carried out from commencement of RTM session till delivery period.

Table-1: RTM Timeline (Phase 1)

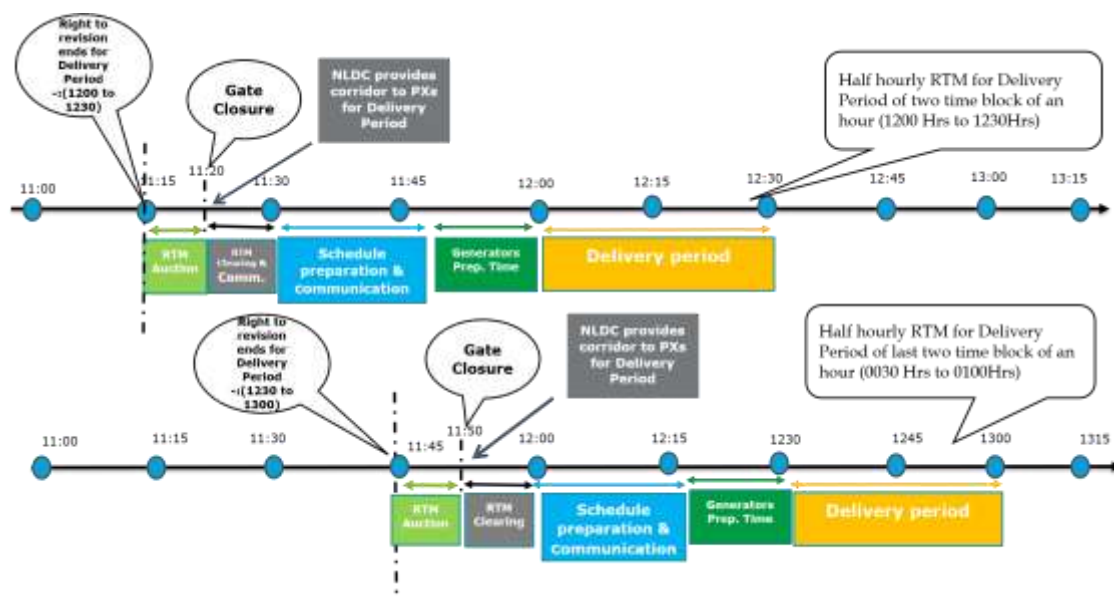
BLOCK	TIMELINE	PHASE	ACTIVITIES
Block X-4	(T-60) to (T-45)	Bidding window for RTM	•Processing of DC and schedule revision requests received up to gate closure and preparation of injection and drawal schedules. •Processing of exigency T-GNA applications. •Bidding by market participants on the Power Exchange platform for RTM and RTM-AS segments – to be finalised by T-45.
Block X-3	(T-45) to (T-30)	RTM clearing	•Matching of buy/sell bids by power exchanges to obtain provisional/unconstrained solution and its transmission to NLDC. •Verification of combined trade volumes against corridor-wise ATC margins and exchange-wise margin allocation. •Fetching of ATC margins by power exchanges, running constrained solution and transmission of final results to NLDC. •Verification of traded volumes against margins and trade acceptance.
Block X-2	(T-30) to (T-15)	SCUC, SCED Optimization & Preparation time	•Scheduling of RTM trades in regional entity schedules •Discovery of MCV and MCP for RTM-AS market by NLDC •Real-time SCUC run followed by SCED run •Scheduling of SCED and SCUC instructions in regional entity schedules • Finalisation of TRAS dispatch requirement for block X •Sequential TRAS dispatch – Market followed by Shortfall, then Emergency, considering generator and system constraints
Block X-1	(T-15) to (T)	Preparation time	• TRAS dispatch incorporated in schedule • Generators Preparation and Ramping time
Block X, X+1	(T) to (T + 30)	Delivery Period	Power is Delivered

20.11 Under **Phase-2 (from 01.04.2027)**: Further reduction of 15 minutes in the timeline for RTM session such that RTM bidding and clearing will take place within

15 minutes instead of 30 minutes, the System Operator would have 15 minutes after clearing the RTM session to prepare and communicate schedules under RTM, SCED, SCUC, and TRAS dispatch and generators would have 15 minutes as preparation time to deliver the finalised schedules. Under phase 2, a 5-minute bidding window shall be provided, followed by 10 minutes of bid clearance. After clearing the RTM, the system operator would have 15 minutes to prepare and communicate schedules under the RTM, SCED, SCUC, and TRAS dispatch. This will further shift the RTM closer to the delivery period by 15 minutes. The stakeholders, including the System Operator (NLDC/RLDCs) and Power Exchanges, would ensure adequate infrastructure is in place, with standardised API integration among Power Exchanges, NLDC, RLDCs, SLDCs, and WBES. The following Fig. 5 shows the timeline for the RTM session under Phase-2 (from 01.04.2027). The detailed sequence of the process to be followed under Phase-2 is depicted schematically in Fig. 2 below, and Table A depicts the number of activities to be executed between gate closure and delivery

20.12 Any revision in schedule made in the odd time block shall be effective from the 5th time block, and any revision made in the even time block shall be effective from the 6th time block. Phase 2 shall be implemented from 01.04.2027 onwards. Fig. 3 depicts the detailed process to be followed in Phase-2, and Table B lists the number of activities to be executed between gate closure and delivery.

Figure- 5: Phase-2 (from 01.04.2027) timeline for Real Time Market



20.13 The following table (Table-2) provides details of various activities carried out from the commencement of the RTM session till the delivery period.

Table-2: RTM Timeline (Phase 2)

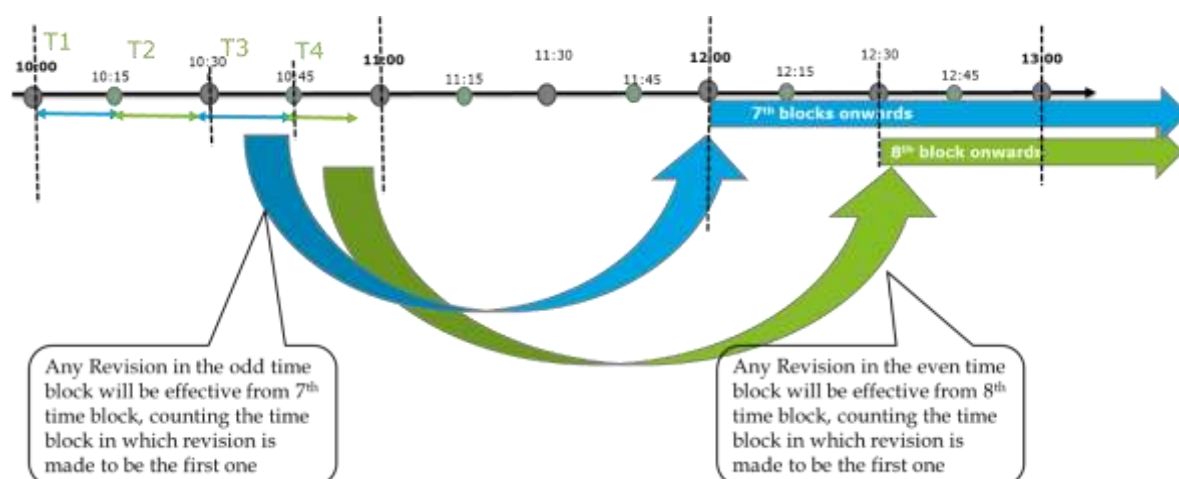
TIME BLOCK	TIMELINE	PHASE	ACTIVITIES
Block X-3	(T-45) to (T-40)	Bidding window for RTM	•Processing of DC and schedule revision requests received up to gate closure and preparation of injection and drawal schedules. •Processing of exigency T-GNA applications. •Bidding by market participants on the Power Exchange platform for RTM and RTM-AS segments – to be finalised by T-40.
Block X-3	(T-40) to (T-30)	RTM clearing	•Matching of buy/sell bids by power exchanges to obtain provisional/unconstrained solution and its transmission to NLDC. •Verification of combined trade volumes against corridor-wise ATC margins and exchange-wise margin allocation. •Fetching of ATC margins by power exchanges, running constrained solution and transmission of final results to NLDC. •Verification of traded volumes against margins and trade acceptance.
Block X-2	(T-30) to (T-15)	SCUC, SCED Optimisation & Preparation time	•Scheduling of RTM trades in regional entity schedules •Discovery of MCV and MCP for RTM-AS market by NLDC •Real-time SCUC run followed by SCED run •Scheduling of SCED and SCUC instructions in regional entity schedules • Finalisation of TRAS dispatch requirement for block X •Sequential TRAS dispatch – Market followed by Shortfall, then Emergency, considering generator and system constraints
Block X-1	(T-15) to (T)	Preparation time	• TRAS dispatch incorporated in schedule Generators Preparation and Ramping Time
Block X, X+1	(T) to (T + 15)	Delivery Period	Power is Delivered

20.14 In view of the above, amendments to Regulation 49 (1) (q) and Regulation 49 (1) (r) have been proposed.

B. Timelines for Revision of Schedule for GNA grantee

20.15 As per the existing scheduling framework under the Indian Electricity Grid Code (IEGC), the beneficiaries are permitted to revise their schedules up to the 7th/8th time block prior to the delivery time block, under Regulation 49(4) of the IEGC. Any revision made in an odd time block takes effect from the 7th time block onward, and any revision made in an even time block takes effect from the 8th time block onward, counting the time block in which the revision is made as the first block. The existing timeline for revision of schedule as per Regulations 49 (4) (c) is depicted in the following Figure 6.

Figure-6: Timeline for Right to revise the Schedule



20.16 As reiterated by the Commission during the introduction of the RTM, the provision regarding 'revision of schedule' is nothing but a product in the electricity market continuum. When the application window for one product expires, the window for another product opens. Accordingly, with revision of timelines for the RTM as proposed in the previous paragraphs, it would have a consequential effect on the 'revision of schedule' for GNA grantee in their bilateral transactions as follows:

Under phase-1 (up to 31.03.2027), the Commission has proposed a reduction of 15 minutes (1 time-block); hence, the provision regarding 'Revision of schedule' for the GNA grantee would also be shifted by 15 minutes (1 time-block). Thus, any revision made in an even time block by the

GNA grantee will take effect from the 6th time block onward, and any revision made in an odd time block by the GNA grantee will take effect from the 7th time block onward, counting the time block in which the revision is made as the first block.

Under Phase-2 (from 01.04.2027), the Commission has proposed further reducing the timeline by 15 minutes; therefore, the provision regarding 'Revision of Schedule' for GNA grantees will also be shifted by another 15 minutes (1 time block). Thus, any revision made in an odd time block will take effect from the 5th time block onward, and any revision made in an even time block will take effect from the 6th time block onward, counting the time block in which the revision is made as the first block.

20.17 The provision regarding 'revision of schedule' for bilateral transactions would be available to the discom and the generator, and could be exercised by them until the real-time market for a specified half-hour commences. Any requirement for power after the end of the right to revise the schedule should be met through the Real-Time Market at the real-time price. Once the RTM commences for a given half-hour delivery period, no further schedule revision is permitted for that period. Timeline for Revision of Schedule for GNA grantee under proposed Amendment is depicted in the following Figure-7.

Figure-7 Timeline for Right to revise schedule under Phase-1 (up to 31.03.2027)

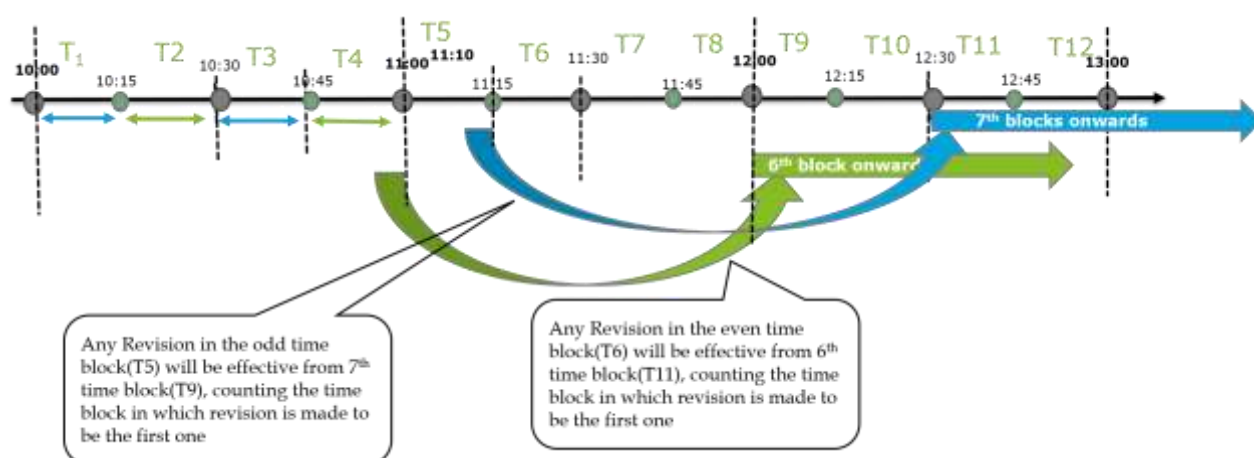
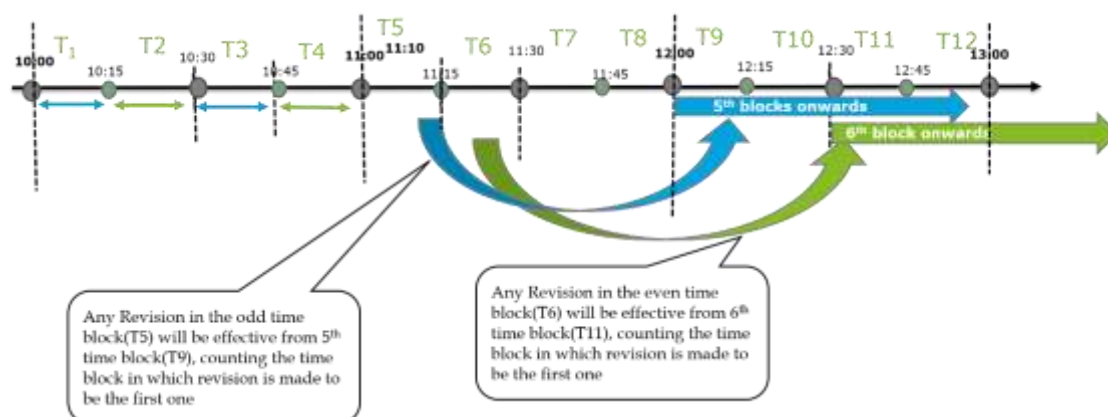


Figure-8 Timeline for Right to revise schedule under Phase-2 (from 01.04.2027)



20.18 In view of the above, an amendment to Regulation 48(2)(b), 48(3)9b), 49 (1) (q), Regulation 49(1)(r), 49(3)(b), 49(4)(c), 49(5)(f) and the first proviso of Regulation 49 (7) has been proposed.

C. Timelines for Revision of schedules on request of buyers which are GNA grantees (sub-clause (c) of Clause (4) of Regulation 49 of the Principal Regulations)

20.19 The revision in the timeline for Real Time Market as proposed above would have consequential effect on the timeline for revision of Declared Capacity and Schedule on account of forced outage of a unit of a generating station or ESS (as an injecting entity) in case of bilateral transactions as per Regulation 49 (7) of the Indian Electricity Grid Code (IEGC). Accordingly, an amendment is proposed to the first proviso to Regulation 49(7) of the Principal Regulations.

D. Timelines for Revision of schedules due to Grid disturbance of category GD-5 (proviso to sub-clause (f) of Clause (5) of Regulation 49 of the Principal Regulations)

20.20 The revision in the timeline for Real Time Market as proposed above would have consequential effect on the timeline for Energy and deviation settlement for the period of Grid disturbance of category 5 causing disruption in injection or drawal of power as per Regulation 49 (5)(f) of the Indian Electricity Grid Code (IEGC). Accordingly, an amendment is proposed to the proviso to Regulation 49(5)(f) of the Principal Regulations.

E. Timelines for Revision of schedule by RLDCs due to congestion or any other constraint (proviso of Sub Clause (b) of Clause 3 of Regulation 49)

20.21 The revision in the timeline for Real Time Market as proposed above would have a consequential effect on the timeline for revision of schedule by RLDCs in the event of a bottleneck in evacuation of power due to outage, failure or limitation in the transmission system or any other constraint necessitating reduction as per sub-clause (b) of Clause 3 of Regulation 49 of the Indian Electricity Grid Code (IEGC). Accordingly, an amendment is proposed to the proviso under sub-clause (b) of Clause (3) of Regulation 49 of the Principal Regulations.

F. Timelines for Revision of Declared Capacity and schedule in case of a forced outage / partial outage of a unit of a generating station or ESS (as an injecting entity) in case of bilateral transactions (First proviso of Clause 7 of Regulation 49)

20.22 The revision in the timeline for Real Time Market as proposed above would have a consequential effect on the timeline for revision of the Declared Capacity and Schedule by RLDCs/ NLDC on account of forced outage / partial outage of a unit of a generating station or ESS (as an injecting entity) in case of bilateral transactions as per Regulation 49 (7) of the Indian Electricity Grid Code (IEGC). Accordingly, an amendment is proposed to the first proviso of Clause (7) of Regulation 49 of the Principal Regulations.

G. Timelines for scheduling from alternate source of power by a Generating Station in case of USD or Forced outage (Sub Clause (b) of Clause 2 of Regulation 48)

20.23 The revision in the timeline for Real Time Market as proposed above would have a consequential effect on the timeline for scheduling from an alternate source of power by a Generating Station in case of USD or forced outage as provided in sub-clause (b) of Clause (2) of Regulation 48 of the Indian Electricity Grid Code (IEGC). Accordingly, an amendment is proposed in Sub-clause (b) of Clause 2 of Regulation 48 of the Principal Regulations.

H. Timelines for scheduling from alternate source of power by a Generating Station in case of USD or Forced outage (Sub-clause (b) of Clause 3 of Regulation 48)

20.24 The revision in the timeline for Real Time Market as proposed above would have a consequential effect on the timeline for scheduling for a station other than REGS replacing its scheduled generation by power supplied from REGS, irrespective of whether such identified sources are located within or outside the premises of the generating station or at a different location, as provided in sub-clause (b) of Clause (3) Regulation 48 of the Indian Electricity Grid Code (IEGC). Accordingly, an amendment is proposed to Sub-clause (b) of Clause 2 of Regulation 48 of the Principal Regulations.

20.25 In view of the above proposed amendments in the time blocks, which are proposed to be implemented in two phases, i.e. (i) up to 31.03.2027 and (ii) from 01.04.2027, the sub-clause (b) of Clause (2) of Regulation 48 of the Principal Regulation shall be read as under:

In the first phase, up to 31.03.2027:

“(b) In case of bilateral transaction, the generating station shall request RLDC to schedule power from such alternate supplier to its beneficiaries, which shall become effective from the 6th or 7th time block, as the case may be, in terms of clause (4) of Regulation 49 of these regulations.”

In the second phase, from 01.04.2027:

“(b) In case of bilateral transaction, the generating station shall request RLDC to schedule power from such alternate supplier to its beneficiaries which shall become effective from 5th or 6th time blocks, as the case may be, in terms of clause (4) of Regulation 49 of these regulations.”

20.26 The sub-clause (b) of Clause (3) of Regulation 48, sub-clause (b) of Clause (3) of Regulation 49, sub-clause (c) of Clause (4) of Regulation 49, sub-clause (f) of Clause (5) of Regulation 49 and first proviso of Clause 7 of Regulation 49 shall be read in different phases of implementation of the proposed amendment as explained above.

20.27 Further, in view of the above proposed amendments, the timelines for scheduling of RTM transactions in two different phases of implementation of the proposed amendment shall be as follows:

(a) Scheduling of RTM transactions (up to 31.03.2027):

Activity	Time
RTM Session open from 00.00 hrs. to 00.30 hrs.	2300 Hrs.
RTM Session closed for 00.00 hrs. to 00.30 hrs.	2315 Hrs.
RTM Clearance & Scheduling	2315 Hrs to 2330 Hrs
NLDC to finalise schedules under RTM, SCED & Ancillary Services	2340 Hrs.
RLDC shall publish the final schedules for despatch	2345 Hrs.

(b) Scheduling of RTM transactions (from 01.04.2027):

Activity	Time
RTM Session open from 00.00 hrs. to 00.30 hrs.	2315 Hrs.
RTM Session closed for 00.00 hrs. to 00.30 hrs.	2320 Hrs.
RTM Clearance & Scheduling	2320 Hrs to 2330 Hrs
NLDC to finalise schedules under RTM, SCED & Ancillary Services	2340 Hrs.
RLDC shall publish the final schedules for despatch	2345 Hrs.
