Grid Controller of India Limited (Grid-India)

National Load Despatch Center (NLDC), New Delhi

दिनांक: 05 December 2022

सेवा में,

All the Stakeholders

विषय: Detailed Procedure for Secondary Reserve Ancillary Services (SRAS)

संदर्भ: Central Electricity Regulatory Commission (CERC) (Ancillary Services) Regulations, 2022

महोदय/महोदया,

CERC (Ancillary Services) Regulations, 2022 was notified on 31st January, 2022. As per the gazette notification of Hon'ble CERC dated 31st October, 2022, the provisions of the Secondary Reserve Ancillary Services (SRAS), shall come into force with effect from 05th December 2022.

As per the above regulations, NLDC has been designated as the Nodal Agency. In compliance to regulation 23 of the aforesaid regulations, a draft detailed procedure for SRAS was formulated by the Nodal Agency. The document was shared on the NLDC website on 23rd September 2022 and comments were invited from stakeholders by 07th Oct 2022. On the request of few stakeholders the last date to submit the comments was extended to 17th October 2022. Two workshops were conducted for the stakeholders by NLDC on 18th November 2022 and 22nd November 2022. Suggestions/feedback received on the draft detailed procedure on SRAS from stakeholders through written communications, and during workshop deliberations have been examined. The detailed procedure for SRAS after duly incorporating the stakeholder inputs/suggestions is enclosed herewith. The aforesaid detailed procedure is also placed on the Grid-India website at https://posoco.in/spinning-reserves/.

सधन्यवाद,

भवदीय,

(देबाशिस दे)

कार्यकारी निदेशक

संलग्न – Detailed Procedure for SRAS in compliance with regulation 23 of the CERC (Ancillary Services), Regulations, 2022

प्रतिलिपि Secretary, CERC

Grid Controller of India Limited (Grid-India)

Nodal Agency - National Load Despatch Centre (NLDC)

Detailed Procedure

for

Secondary Reserve Ancillary Services (SRAS)

Prepared in Compliance to regulation 23 of
Central Electricity Regulatory Commission (Ancillary Services)
Regulations, 2022

December 2022

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1.0 Preamble

1.1 Maintaining frequency stability is critical for the integrated operation of a large interconnected power system like India. Generally, frequency response of any power system can be characterized by different time window-based responses, such as, inertial, primary frequency, secondary frequency, and tertiary frequency response.

1.2 Secondary response is a reliability service and acts as a replacement to the exhausted primary frequency reserves and for correction of Area Control Error (ACE) and hence helps in maintaining frequency stability and reliability.

1.3 Secondary frequency control has been operationalized in the Indian power system through Automatic Generation Control (AGC) pan-India since 20th July 2021. A total of 66 power plants with an installed capacity of around 64000 MW have been continuously operating 24x7.

1.4 Central Electricity Regulatory Commission (CERC) has notified (Ancillary Services) Regulations, 2022, hereinafter referred to as the "AS Regulations". It has provided for Ancillary Services in the form of Secondary Reserve Ancillary Services (SRAS) and Tertiary Reserve Ancillary Services (TRAS). As per the regulations, NLDC has been designated as the Nodal Agency. Further, it has been provided that a detailed procedure on Secondary Reserve Ancillary Services (SRAS) has to be submitted by the Nodal Agency (Regulation 23(1)) for the information of the Hon'ble Commission after stakeholder consultation.

1.5 SRAS means the Ancillary Service comprising SRAS-Up and SRAS-Down, which is activated and deployed through secondary control signal.

1.6 National Load Despatch Centre i.e. the Nodal Agency, in coordination with RLDCs and SLDCs, would estimate the quantum of requirement of SRAS at the regional level after factoring in the reserves for each state control area, for such period and based on such methodology as specified in the Grid Code and publish the same on its website. Nodal Agency has proposed an interim methodology for estimation of reserves for approval of the Central Commission post stakeholder consultations.

1.7 This procedure provides the aspects of procurement, deployment, payment, and all other aspects of SRAS in accordance with the CERC (Ancillary Services) Regulations, 2022.

2.0 Objective

2.1 The objective of this procedure is to lay down the roles and methodology to be followed for the aspects of procurement, deployment, payment, performance evaluation, and all other aspects of SRAS to be followed by the Nodal Agency (NLDC), RLDCs, SLDCs, RPCs, CTUIL, Communication Providers, and SRAS Providers.

3.0 Definitions

3.1 '**Communication Providers'** would provide end to end redundant communication system between SRAS Provider and Nodal Agency. CTUIL shall be the communication provider between Nodal Agency and SRAS Provider.

3.2 All the words and expressions used in the Procedure shall have the same definition as assigned to them in various CERC Regulations.

4.0 Roles

4.1 Nodal Agency

4.1.1 Nodal Agency would generate the automated AGC signal (SRAS Up or SRAS Down) which would be followed by the SRAS Provider to adjust the generation to maintain or restore grid frequency within the allowable band as specified in the Grid Code or replenish primary reserves.

4.1.2 Nodal Agency would, in coordination with RLDCs and SLDCs, estimate the quantum of requirement of SRAS on day-ahead basis and re-asses incremental requirement, if any, on real time basis based on methodology notified on the NLDC website.

4.1.3 Nodal Agency would specify the requirements of the bi-directional communication system between SRAS Provider and NLDC/RLDCs.

4.1.4 Nodal Agency would detail the metering and SCADA telemetry to be in place for monitoring and measurement of energy delivered under SRAS by the SRAS Providers.

4.1.5 Nodal agency would auto-calculate Area Control Error (ACE) for each region. Frequency Bias Coefficient (Bf) shall be assessed and declared by the Nodal Agency. Offset shall be used to account for measurement errors and shall be decided by the Nodal Agency for the respective region.

4.1.6 Nodal Agency would specify the technical and commercial parameters to be submitted by the SRAS Providers.

4.1.7 Nodal Agency would select the SRAS Provider for provision of SRAS-Up/Down based on the Custom Participation Factor, which would be determined for each SRAS provider.

4.1.8 Nodal Agency would provide the methodology for the computation for payment for SRAS and incentive based on performance.

4.1.9 The actual response of SRAS Provider against the secondary control signals from the Nodal Agency to the control centre of the SRAS Provider would be monitored by the Nodal Agency.

4.1.10 In respect of the SRAS providers and of Regional Entities (where Intra-state SRAS is embedded), Nodal Agency would provide data to respective RPCs, through RLDCs, for the accounting and settlement through Regional Deviation and Ancillary Service Pool Account on a weekly basis.

4.1.11 The Nodal Agency would publish information on its website about SRAS procured, and dispatched on weekly basis and submit monthly detailed feedback reports to the Central Commission.

4.1.12 In the case of intra-state generators participating in SRAS, Nodal Agency shall share the real time AGC MW quantum to the respective RLDC through ICCP.

4.1.13 In the case of intra-state generators participating in SRAS, Nodal Agency shall share the weekly SRAS 5-minute MWh and 15-minute MWh ex-bus quantum to the respective RLDC for onward transmission to the respective SLDCs.

4.2 Regional Load Despatch Centres (RLDCs)

4.2.1 The respective RLDCs would maintain the relevant scheduling data of inter-state entities during the SRAS operation (including but not limited to generating station-wise installed capacity, declared capacity, schedule, Un-Requisitioned Surplus (URS), generator wise SRAS schedules for up/down and requisitions from the generating stations). RLDCs shall verify the SRAS quantum data received from Nodal Agency. The implemented schedule data would be prepared by the RLDCs after including SRAS quantum.

4.2.2 In the case of intra-state generators participating in SRAS, RLDC shall forward the real time AGC MW quantum to the respective SLDC through ICCP.

4.2.3 In the case of intra-state generators participating in SRAS, RLDC shall forward the weekly SRAS 5-minute MWh and 15-minute MWh ex-bus quantum to the respective SLDC.

4.3 State Load Despatch Centres (SLDCs)

4.3.1 The respective SLDCs would maintain the relevant scheduling data of intra-state entities during the SRAS operation (including but not limited to generating station-wise installed capacity, declared capacity, schedule, Un-Requisitioned Surplus (URS), generator wise SRAS schedules for up/down and requisitions from the generating stations).

4.3.2 SLDCs shall use the real time AGC MW data obtained through ICCP from the RLDCs, and incorporate it to the state's net schedule for the purpose of monitoring deviations.

4.3.3 AGC DeltaP quantum for intra-state generators shall be incorporated in state's net schedule (with appropriate sign) for the purpose of computation of deviations by SLDC or appropriate agency in the state. Hence, generation of the intra-state generator under AGC would not be considered as deviation of the state.

4.3.4 SLDCs shall use the 15-minute SRAS MWh quantum data received from RLDC for deviation settlement.

4.4 Regional Power Committees (RPCs)

4.4.1 The respective RPCs shall prepare weekly SRAS accounts based on the data provided to them by the Nodal Agency/RLDCs.

4.4.2 For the intra-state generators, the settlement of payments towards SRAS-Up/SRAS-Down 15-minute MWh along with the performance based incentive would be done by the RPC with the respective Regional Deviation and Ancillary Service Pool Account.

4.5 SRAS Providers

4.5.1 SRAS Providers would provide the technical and commercial parameters to the Nodal Agency as per **Annexure – I**.

4.5.2 SRAS Provider shall increase or decrease the generation as per the automated AGC signal (SRAS Up or SRAS Down) by Nodal Agency.

4.5.3 SRAS Providers other than section-62 plants, shall provide the bank account details for settlement of AGC incentives/mileage (as per format **SRAS-3**).

4.6 Communication Providers

4.6.1 Communication Providers would provide end to end redundant communication system between SRAS Provider and Nodal Agency in accordance with CERC (Communication System for inter-State transmission of electricity) Regulations, 2017.

4.6.2 Communication Providers shall provide two different paths for maintaining redundancy of the communication path ensuring route diversity and dual communication.

4.6.3 In case of multiple Communication Providers involving CTUIL and STU, CTUIL shall coordinate with STU for establishing communication between Nodal Agency and the intra-state SRAS Provider.

4.6.4 Communication Providers shall have Network Management System for monitoring and troubleshooting communication links on a 24x7 basis in line with CERC (Communication System for inter-state transmission of electricity) Regulations, 2017.

4.6.5 Assessment and maintenance of communication system has to be done by Communication Providers in real-time to maintain the availability of communication system.

4.6.6 Communication Providers shall coordinate with their infrastructure providers/maintenance providers/vendors/OEMs to provide end to end communication between SRAS provider and Nodal Agency with round-the-clock support and prompt response as per Standard Operating Procedure issued by Nodal Agency **(Annexure-II).**

4.6.7 Four (two for primary control centre-PCC and two for back up control centre-BCC) ethernet ports shall be provided by the Communication Provider at the nearest available wide band node to the SRAS Provider.

5.0 Eligibility of SRAS Provider

5.1 A generating station or an entity having energy storage resource, on standalone or aggregated basis, connected to inter-State transmission system or intra-State transmission system, shall be eligible to provide Secondary Reserve Ancillary Service, as an SRAS Provider, if it:

5.1.1 has bi-directional communication system with NLDC/RLDC;
5.1.2 is AGC-enabled, in case of a generating station;
5.1.3 can provide minimum response of 1 MW;
5.1.4 has metering and SCADA telemetry in place for monitoring and measurement of energy delivered under SRAS
5.1.5 is capable of responding to SRAS signal within 30 seconds and providing the entire SRAS capacity obligation within fifteen (15) minutes and sustaining at least for the next thirty (30) minutes;

5.2 Intra-state generators shall inform and take consent from the respective SLDC (as per format SRAS-3) to become an SRAS Provider.

5.3 SRAS Provider shall complete the Open Loop and Closed Loop tests conducted by the Nodal Agency as per **Annexure-III**.

6.0 Bi-directional Communication System

6.1 IEC-60870-5-104 protocol is to be used for setting up bi-directional communication between SRAS provider and Nodal Agency using communication system provided by Communication Provider.

6.2 SRAS provider shall arrange a dedicated Remote Terminal Equipment (RTU) for AGC, Routers, Switches and any converters (like optical to ethernet) for setting up communication using IEC-60870-5-104 protocol.

6.3 The minimum generic hardware specifications for bi-directional communication system are provided in **Annexure-IV**. Depending on the number of units and available infrastructure, SRAS Provider needs to plan, customize and procure its hardware including spares for facilitating bi-directional communication system.

6.4 RTU is needed to be synchronized with GPS clock signal or it has to be synced with Nodal Agency servers via clock sync protocol scan.

6.5 SRAS Provider is accountable for RTU maintenance and troubleshooting for participation in SRAS. The RTU shall be capable of handling arithmetic and logical functions, archival of data and creating reports.

7.0 SCADA Telemetry and Metering

7.1 SCADA Telemetry

7.1.1 Telemetry provided via IEC-104 needs to be configured as various types of points-

7.1.1.1 Single Point Digital Status: This is a single point digital status which may be configured and sent by SRAS provider to Nodal Agency as per the requirement.

7.1.1.2 Dual Point Digital Status: This is a dual point digital status (Circuit Breaker Status of Units is used to configure as dual point digital status) which may be configured and sent by SRAS provider to Nodal Agency as per the requirement.

7.1.1.3 Double Point Digital Command: This is a dual point command which may be configured and received by SRAS provider from Nodal Agency as per the requirement.

7.1.1.4 Input Analog Point: This is an analog point which may be configured and sent by SRAS provider to Nodal Agency as per the requirement.

7.1.1.5 Set point from Nodal Agency: This is an analog point which may be configured and received by SRAS provider from Nodal Agency as per the requirement. This point would be used for sending SRAS despatch instructions from Nodal Agency.

7.1.2 The detailed signal list used for Automatic Generation Control (AGC) along with logics to be implemented by the SRAS Provider in the RTU/Digital Control System (DCS) is attached as **Annexure-V.**

7.2 Measurement and Metering

7.2.1 All measurements of secondary control signals from the Nodal Agency to the control centre of the SRAS Provider and actual response of SRAS Provider shall be carried out at gross level on post-facto basis using SCADA data.

8.0 Computation of Area Control Error

8.1 The Area Control Error (ACE) for each region would be auto-calculated at the control centre of the Nodal Agency based on telemetered values and the external inputs, as per the following formula:

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

Where,
Ia = Actual net interchange in MW (positive value for export)
Is = Scheduled net interchange in MW (positive value for export)
Bf = Frequency Bias Coefficient in MW/0.1 Hz (negative value)
Fa = Actual system frequency in Hz
Fs = Schedule system frequency in Hz
Offset = Provision for compensating for measurement error

8.2 The detailed methodology to be followed by Nodal Agency for calculation and monitoring of Area Control Error (ACE) is attached at **Annexure – VI.**

8.3 Nodal Agency may operate SRAS in any of the three control modes namely, tie-line bias control mode, flat frequency control mode or flat tie-line control mode depending on grid requirements. The AGC operation modes shall be archived for post-despatch purposes by the Nodal Agency.

8.4 NLDC shall operate the control areas in flat frequency control mode by default, for ensuring economy and harnessing diversity.

8.5 In case of congestion or anticipated congestion, with flows from or towards any area exceeding or nearing the Available Transfer Capability (ATC) limits, Nodal Agency shall operate such control areas in tie-line bias mode.

8.6 If there are any radial control areas with commercial or technical requirements of strict adherence to tie-line schedules, such areas can be operated in flat tie-line control mode.

8.7 Nodal Agency shall suspend operation of one or more power plants or control areas, for reasons like intermittent communication, reboots, software updations, etc. When 'Suspended,' AGC sends a control signal to one or more power plants or control areas, to make the correction by AGC to zero.

9.0 Reserve Utilization for SRAS

9.1 SRAS shall be procured on regional basis by the Nodal Agency through the regulated mechanism as specified in the CERC (Ancillary Services) Regulation, 2022. No explicit procurement of reserves would be made in SRAS as of now. Un-dispatched surplus available with the SRAS Providers would be utilized as reserves for SRAS.

9.2 An SRAS Provider willing to participate in SRAS shall be required to provide standing consent to the Nodal Agency for participation in the next month 'M' by 8th day of the current month i.e. 'M-1' (if 8th day is holiday, then next working day), which shall remain valid till it is modified or withdrawn. The standing consent, except in case of forced outage, cannot be modified or withdrawn without giving notice of at least forty-eight (48) hours.

9.3 The SRAS Providers shall inform changes, if any, in the technical and commercial parameters of Annexure – I on monthly basis. In the case of absence of any update, the last available revision shall be considered by the Nodal Agency.

9.4 The SRAS Providers that are generating stations whose tariff is determined under section 62 of the Act, would declare their energy charges upfront on monthly basis.

9.5 The SRAS Providers, other than those covered under section 62 of the Act, shall be required to declare the compensation charges upfront on monthly basis.

9.6 There shall not be any commitment charge for the SRAS providers.

10.0 Activation and Deployment of SRAS

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

10.1.1 Considering a region as control area, Area Control Error (ACE) of the region, going beyond the minimum threshold limit of ±10 MW.

10.1.2 Such other events as specified in the Grid Code/CERC regulations on Ancillary Services.

10.2 SRAS shall be despatched on regional basis through secondary control signals by the Nodal Agency.

10.3 Secondary control signal for SRAS-Up and SRAS-Down shall be sent to the SRAS Provider every 4 seconds by the Nodal agency.

10.4 SRAS Provider shall allow its control centre to follow the secondary control signal for SRAS-Up or SRAS-Down automatically without manual intervention.

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

10.6 All the signals as mentioned in the detailed signal list at **Annexure-V** shall be shared by the SRAS Provider through IEC 104 protocol directly with the Nodal Agency. Nodal Agency shall share the same with the respective RLDC through ICCP.

10.7 The SRAS Provider shall share real-time data with NLDC and the concerned RLDCs as per the Standard Operating Guidelines for the SRAS Providers **(Annexure-VII).** These guidelines would be revised time to time, based on experience and with the introduction of new technologies.

10.8 For monitoring of AGC, SRAS provider, Communication Provider and Nodal Agency shall maintain suitable SCADA/IT dashboards.

10.9 The activation and deployment of SRAS for intra-state generators can be done by NLDC, as per the guidelines mentioned in Section-9 of this procedure and **Annexure-VIII.** The intra-state generators under SRAS would be dispatched to control regional ACE.

11.0 Selection of SRAS Providers and Despatch of SRAS

11.1 SRAS Provider shall be selected, on regional basis, by the Nodal Agency for providing SRAS-Up or SRAS-Down based on the Custom Participation Factor.

11.2 AGC uses smooth ACE which is the output of the PID controller and uses raw ACE as input. Smooth ACE signal shall be allocated among the SRAS Providers to meet SRAS requirement of the system based on the normalised Custom Participation Factor subject to the ramp limited resources available with the SRAS Provider(s).

11.3 Custom Participation Factor shall be computed for deciding the distribution of the Smoothed Area Control Error between the power plants in a control area.

11.4 Custom Participation Factor shall be calculated based on the normalized values of the declared Ramp Rate and Energy Charge (Section 62 plants) or Compensation Charge (Other than Section 62 plants).

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

11.5.1 Rate Participation Factor (Ramping capability in MW/min); and
11.5.2 Cost Factor (energy charge or compensation charge, as the case may be).

11.6 The Custom Participation Factor for SRAS-Up shall be directly proportional to the normalised Rate Participation Factor and inversely proportional to the normalised Cost Factor.

11.7 The Custom Participation Factor for SRAS-Down shall be directly proportional to the product of the normalised Rate Participation Factor and normalised Cost Factor.

11.8 Based on the above principles, Custom Participation Factor shall be calculated which shall be normalised to determine the participation of each SRAS Provider.

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

11.10 For the Gas based power plants, weighted average of the fuel-wise energy charges shall be used for the calculation of the normalized Custom Participation Factor. The weightage shall be based on the fuel-wise Declared Capability on bar.

11.11 A sample illustration with five (5) SRAS Providers (A, B, C, D and E) for calculation of Custom Participation Factor has been shown in Table-1 for Up regulation.

Plant name	Declared Capacity Pmax (MW)	Schedule (MW)	UP Reserve (MW)	Rate Factor (MW/min)	Cost Factor (paise/kWh)	Normalized Rate Participation Factor	Normalized Cost Factor	Custom Participation Factor (CPF)	Normalised Custom Participation Factor (NCPF)	SRAS-Up Requirement (MW) (assumed)	SRAS-UP Capacity with NCPF	SRAS Desired Signal	4-second ramp rate(MW/min)	SRAS Control signal for the next 4 seonds	SRAS Control signal after 8 seconds$	Time to achieve Desired SRAS@ at "m" (minutes)
	(a)	(b)	(c)=(a)-(b)	(d)	(e')	(f) = [(d)/sum(d)]	(g) = [(e)/sum(e)]	(h) = [(f)/(g)]	(i) = [(h)/sum(h)]	(k)	(l) = (i)x(k)	(m) = (l) subject to (c)	(n)=(d)*4/60	(o)=(n)	(p)= (o)+/-(n)	(q)=(m)/(d)
A	4150	4000	150	41.5	194	0.16	0.15	1.0	0.19	340	66	65.8	2.8	2.8	5.5	1.58
B	400	250	150	100	231	0.38	0.18	2.1	0.39		133	149*	6.7	6.7	13.3	1.49
C	1050	950	100	10.5	264	0.04	0.21	0.2	0.04		12	12.2	0.7	0.7	1.4	1.62
D	1000	900	100	100	265	0.38	0.21	1.8	0.34		116	100#	6.7	6.7	13.3	1.00
E	1320	1200	120	13.2	314	0.05	0.25	0.2	0.04		13	12.9	0.9	0.9	1.8	0.98

Note:

(i) "#" SRAS desired signal of 16 MW clipped from SRAS Provider D, considering the SRAS-Up reserves available with SRAS Provider D.

(ii) "*"SRAS desired signal of 16 MW clipped from SRAS Provider D is allocated to the SRAS Provider with the highest normalised Custom Participation Factor first and so on - in this case, it is allocated to SRAS Provider B.

(iii) "$" AGC shall follow desired signal with ramp rate (n) if ACE (k) is in the same direction (+); (-) means oppsite direction like -340

(iv)"$"ACE (column k) can change direction frequently and so does (m); However, (p) changes only based on previous (o)+/-(4 second ramp rate)

(v)@ Assuming that ACE is the same direction for those many minutes

12.0 Performance Assessment and Incentive Calculation

12.1 Average of SRAS-Up and SRAS-Down MW data shall be calculated by the Nodal Agency for every 5 minutes in absolute terms using archived SCADA data at the Nodal Agency. This data would be reconciled with the data received from the SRAS Provider at the Nodal Agency and shall be used for performance assessment as well as incentive calculation.

12.2 All measurements of secondary control signals from the Nodal Agency to the control centre of the SRAS Provider and actual response of SRAS Provider shall be carried out on post-facto basis using SCADA data.

12.3 The actual response of SRAS Provider against the secondary control signals from the Nodal Agency to the control centre of the SRAS Provider shall be monitored by the Nodal Agency.

12.4 Performance of the SRAS Provider shall be measured by the Nodal Agency by comparing the actual response against the secondary control signals for SRAS-Up and SRAS-Down sent every 4 seconds to the control centre of the SRAS Provider measured using 5-minute average data.

12.5 When the power plant is in Remote, the Actual MW should follow AGC Set Point. Performance metric is measured by plotting the Output versus Input. Actual MW, RULSP, RGMO are available through SCADA every 4 seconds at gross level (before auxiliary consumption) from the dedicated RTU. The 4 seconds SCADA data is converted to five minutes average MW data. Consider Circuit Breaker Status (CB Status) and LR Status (Local/Remote) status signals in calculations, although DeltaP calculated at the plant level automatically becomes zero when CB or LR Status is OFF. Take CB Status and LR Status at the start of each 5-minutes time block. Map CB status ON as 1 (Note that as CB is a double point signal, its ON value will be 2. Map the same to 1, for multiplication purposes in the formula). Similarly, Map CB Status OFF as 0. Local Remote status (LR) is a single point signal. Map Local as 0 and Remote as 1. For 'n' units,

- Output = $\sum_{i=1}^{n}((Actual\ MW_n - RULSP_n - RGMO_n) * CB_n * LR_n)$
- Input = $\sum_{i=1}^{n}((DeltaP_n) * CB_n * LR_n)$
- Plot a scatter plot of Output vs Input.
- 288 data points per plant for one day would appear on the scatter plot. Each data point (dot) represents the 5-minute time block performance of the SRAS Provider.
- Add a Trend Line (Y=mX) to the plot with Intercept=0. Display equation on chart. Display R^2 value also.
- Check the value of slope or 'm' in Y=mX. Ideal performance would be Y=X.
- Say the equation is Y=0.8X, then consider the performance is 80%. for that day. Performance would be evaluated for each day of the week. There would be one performance metric value calculated for the whole day for each SRAS Provider (see Format SRAS-2).
- If the RGMO MW input to the governor data is not telemetered by the SRAS Provider, consider the value as zero.
- Note that a poor R^2 value (< 0.5) indicates that the trend line fits with a low confidence, and there may be some external factors, creating outliers, disturbing the actual response. Nodal Agency would keep monitoring and intimate the SRAS Provider to investigate the possible causes, if a sustained low value of R-square is noted. Presently, R^2 value is not being used in the incentive calculation process to keep the mechanism simple, however, R^2 would be constantly reviewed by the Nodal Agency for providing further feedback to CERC.
- If performance is more than 100%, clamp the value to 100%. More than 100% performance may also indicate poor control tuning and any other issue, Nodal Agency would keep monitoring and intimate the SRAS Provider to investigate the possible causes, if sustained over response is noted.

12.6 The Output MW data is derived from Actual MW, RULSP and RGMO MW, which are all telemetered SCADA signals and may contain some noise. The method mentioned in **Annexure-IX** would be used for filtering the Gross Output MW data while calculating the performance of the power plants under AGC. As a result, there would be minimal or no manual intervention while carrying out these calculations.

12.7 SRAS Provider shall be eligible for incentive based on the performance measured and the 5-minute MWh data calculated for SRAS-Up and SRAS-Down aggregated over a day, as under:

Actual performance vis-à-vis secondary control signal for an SRAS Provider	Incentive Rate (paise/kWh)
95 % and above	(+) 50
75 % to below 95%	(+) 40
60 % to below 75%	(+) 30
50% to below 60%	(+) 20
20 % to below 50%	(+) 10
Below 20%	0

12.7.1 Incentive payments shall be calculated for each SRAS Provider, being a generating station, for energy supplied for a day as follows:
Incentive for SRAS Provider = Actual Response (MWh) x (1-NAC) x Incentive Rate

12.7.2 for each SRAS Provider being an entity other than a generating station, for energy supplied for a day as follows:
Incentive for SRAS Provider = Actual Response (MWh) x Incentive Rate

Where,
'Actual Response' is the actual energy output (in MWh) of the SRAS Provider communicated to the Nodal Agency aggregated over 5 minutes in absolute terms and then summed for a day.

'NAC' is percentage Normative Auxiliary Energy Consumption for similar class of generating stations, as specified in the Tariff Regulations.

'Incentive Rate' in Paise/kWh is the incentive rate applicable based on the performance assessment of SRAS Provider.

12.8 The overall performance evaluation during the combined cycle operation of the gas based power plants would be based solely on the performance of the GTs.

12.9 SRAS Providers shall not place any redundant lag filters or low pass filters which might delay the start of the power plant response beyond 30 seconds. Any non-compliance would automatically affect the performance of the SRAS Provider, measured every day.

13.0 Failure in performance of SRAS Provider

13.1 Poor Performance Metric indicates an underlying problem such as restrictive/conservative limits imposed by the SRAS Provider on the AGC Signal, incorrectly tuned control systems, non-understanding the operating guidelines etc.

13.2 Performance below 20% for two consecutive days by an SRAS Provider shall make the SRAS Provider liable for disqualification for participation in SRAS for a week by the Nodal Agency. The details of such SRAS provider and the period of disqualification shall be provided by Nodal Agency through respective RLDCs (Format-SRAS2) to RPCs.

13.3 Respective RPCs shall publish the same (Format-SRAS2) along with (FormatSRAS1). Supporting data as per mutually agreed format will be furnished by NLDC to RPCs. If disqualified by the Nodal Agency, an SRAS Provider shall be eligible to participate in SRAS again only after rectification of the issues and providing satisfactory explanation by email.

13.4 Violation of directions of the Nodal Agency for SRAS under these Regulations shall make the SRAS Providers liable for penalties.

14.0 Cyber Security

14.1 SRAS Providers shall take necessary cyber security measures for the purpose of grid security and plant safety. SRAS Providers shall ensure that no extra devices are connected to the AGC equipment and regular monitoring may be ensured. SRAS Providers shall submit the signed undertaking as per **Annexure-X** to the Nodal Agency.

15.0 Shortfall in SRAS

15.1 All generating stations, whose tariff is determined by the Commission under Section 62 of the Act including those having Un-Requisitioned Surplus (URS) power after declaration of the Real Time Market (RTM) results, shall be deemed to be available for use by the Nodal Agency for SRAS, subject to technical constraints of such generating stations.

15.2 The generating stations as referred to above, whose URS is despatched as SRAS-Up shall be paid their energy charge and incentive.

15.3 The generating stations as referred to above, if despatched as SRAS-Down shall pay back to the Deviation and Ancillary Service Pool Account and shall be paid incentive.

16.0 SRAS Despatch in case of Emergency Conditions

16.1 In case the Nodal Agency requires any generating station to provide Ancillary Services to meet the emergency conditions for reasons of grid security as per the provisions of the Grid Code, such generating station shall be compensated at the rate of the energy charge as determined under Section 62 of the Act or adopted under Section 63 of the Act, or at the rate of the compensation charge declared by the AS provider, as the case may be.

17.0 Energy Accounting of SRAS

17.1 Deviation of AS Provider in every 15 minutes time block shall be calculated as under and settled as per the procedure of the DSM Regulations:

17.1.1 MWh Deviation for AS Provider = (Actual MWh of AS Provider) – (Scheduled MWh of AS Provider including TRAS MWh despatched) – (SRAS MWh of AS Provider despatched)

17.2 SRAS Provider shall archive the below signals for the purpose of accounting and send the data of the previous week to the Nodal Agency through email every Monday in the format provided by NLDC.

17.2.1 5-minute average MW and 5-minute MWh of the AGC input (DeltaP) provided to the power plant control system, which is added to the load set point. Note that DeltaP shall be calculated (non-zero) only when the unit is on bar and in Remote.

17.2.2 15-minute average MW and 15-minute MWh of the input (DeltaP) provided to the power plant control system, which is added to the load set point. Note that DeltaP shall be calculated (non-zero) only when the unit is on bar and in Remote.

17.2.3 Gas based SRAS Providers shall provide the fuel-wise details of 5-minute average MW, 5-minute MWh, 15-minute average MW and 15-minute MWh. They shall also provide 15-minute block-wise, Gas Turbine-wise details of whether the units were operated in open cycle or combined cycle.

17.3 Nodal Agency through respective RLDCs shall furnish 5-minute and 15-minute average MWh SCADA data of SRAS Provider to RPCs on weekly basis along with performance data as per formats SRAS-1 and SRAS-2.

17.4 In the case of intra-state generators participating in SRAS, Nodal Agency shall share the weekly SRAS 5-minute MWh and 15-minute MWh ex-bus quantum to the respective RLDC for onward transmission to the respective RPCs and SLDCs.

17.5 AGC DeltaP quantum (SRAS-Up/SRAS-Down MW) for intra-state generators shall be incorporated in state's net schedule (with appropriate sign) for the purpose of computation of deviations by SLDC, RLDC, RPCs and by appropriate agency in the state. Hence, generation of the intra-state generator participating in SRAS would not be considered as deviation of the state. SLDCs and RPCs shall use the 15-minute SRAS MWh quantum data received from RLDC for implemented schedule preparation and deviation settlement.

17.6 For the intra-state generators, the settlement of payments towards SRAS-Up/SRAS-Down 15-minute MWh along with the performance based incentive would be done by the RPC with the respective Regional Deviation and Ancillary Service Pool Account.

17.7 Accounts (as per Formats **SRAS-1** and **SRAS-2**) would be prepared by the concerned RPC.

17.8 No separate bills shall be raised for this purpose. No retrospective settlement of energy charge or compensation charge for SRAS, as the case may be, shall be undertaken.

17.9 RPCs shall clamp the net implemented schedule of the SRAS Providers between technical minimum and declared capability, if there is a violation because of SRAS Up/Down MW, as physical limits are already honoured by AGC.

18.0 Settlement of SRAS

18.1 The payment to SRAS Provider(s) shall be from the surplus available in Deviation and Ancillary Service Pool Account of the concerned Region where the SRAS Provider(s) is located.

18.2 The payments related to the SRAS shall be settled from the concerned RLDC's "Regional Deviation and Ancillary Service Pool Account" before transfer of any residual amount to the PSDF.

18.3 The bank interest and the interest received due to default in payment of Deviations Charges accumulated in "Regional Deviation and Ancillary Service Pool Account" shall also be considered as surplus along with principal amount for payment available in Regional Deviation and Ancillary Service Pool Account.

18.4 The Deviation and Ancillary Service Pool Account shall be charged for the full cost of despatched SRAS-Up including the energy charge or the compensation charge, as the case may be, for every 15-minute time-block as well as the incentive for SRAS, for every 5-minute time interval, payable to the concerned SRAS Provider.

18.5 SRAS Provider shall pay back to the respective "Deviation and Ancillary Service Pool Account", at the rate of their Energy charge or compensation charge, as the case may be, for the SRAS-Down MW quantum despatched for every 15 minutes time block.

18.6 The concerned RPC, using block wise schedules SRAS-Up/Down provided by concerned RLDC on weekly basis, shall compute and furnish the following details along with the DSM Account under separate account head of SRAS:

18.6.1 Total Energy scheduled in SRAS-Up of each SRAS-Provider.

18.6.2 Energy charges/Compensation charges payable to SRAS providers from the pool in case of SRAS-Up

18.6.3 Energy charges/Compensation charges payable by SRAS providers to the pool in case of DOWN regulation.

18.6.4 Incentive details of each SRAS-Provider based on the performance

18.6.5 For computing the account for Gas based SRAS Providers, RPCs shall use the provided fuel-wise details of 5-minute MWh, 15-minute MWh, and Gas Turbine-wise details of whether the units were operated in open cycle or combined cycle. In case of non-availability of the information from the SRAS Providers, RPCs shall prepare the accounts based on the Declared Capability (on bar), RLDC Schedule and inter se merit order of energy charges/compensation charges of different fuels.

18.7 The Payment to SRAS Provider(s) shall be made on net basis.

18.9 Any surplus accumulated in Deviation and Ancillary Service Pool Account due despatch of SRAS-Down after adjusting the payment liability of SRAS-Up provider(s) or interest accumulated due to delay in payment received from SRAS-Up provider (s) shall not be treated as monthly surplus accumulated in Deviation and Ancillary Service Pool Account and shall be retained in Deviation and Ancillary Service Pool Account for onwards settlement of Ancillary Service.

18.10 In case of deficit in the Deviation and Ancillary Service Pool Account for payment to SRAS Providers, surplus amount available in other region's Deviation and Ancillary Service Pool Account shall be used for such payment.

18.11 In case of SRAS provider to receive charges from respective DAS Pool Account on net basis, then, payment to the concerned SRAS provider shall be made within 15 (fifteen) days of the issue of statement of SRAS Account by the respective RPC.

18.12 In case of SRAS Provider to pay back to respective DAS Pool Account on net basis, then, concerned SRAS provider shall pay back within 10 (ten) days of the issue of statement of SRAS Account by the concerned RPC.

18.13 If payments to the SRAS Provider are delayed beyond Fifteen (15) days from the date of issue of the statement by the respective RPC, the SRAS Provider shall be paid simple interest @ 0.04% for each day of delay.

18.14 If payments by the SRAS Provider are delayed beyond ten (10) days from the date of issue of the statement by the Secretariat of the respective Regional Power Committee, the defaulting SRAS Provider shall pay simple interest @ 0.04% for each day of delay.

18.15 Liability to pay interest for the delay in payments to the "DAS Pool Account" shall remain till interest is not paid; irrespective of the fact that SRAS-Up Providers who have to receive payments have been paid from the "Regional DAS Pool Account Fund" in part or full.

18.16 The details of interest statement shall be prepared by the respective RPCs as per details received from concerned RLDCs.

18.17 Compensation due to Part Load Operation or any other charges not specified in the CERC (Ancillary Services) Regulations, 2022, shall not be payable to the SRAS providers for providing SRAS.

18.18 The quantum of schedule under SRAS Up and Down shall not be considered for the purposes of incentive calculation for the SRAS Provider by the concerned RPC.

18.19 Quarterly reconciliation of the SRAS Account shall be done by the respective RLDCs with the SRAS Providers.

19.0 Revision of the procedures

Notwithstanding anything contained in this Procedure, NLDC/RLDCs may take appropriate decisions in the interest of System Operation. Such decisions shall be taken under intimation to CERC and the procedure shall be modified/amended in consultation with Stakeholders and amendment in procedure will be informed to the CERC, as necessary.

Annexure – I: Technical and Commercial Parameters of SRAS Providers

Hydro Generator Details for Participation in Secondary Reserve Ancillary Service Provider (SRAS)

From: (Name of SRAS Provider Generating Station) / (Name of Owner Organization)
To: NLDC/NRPC/WRPC/SRPC/ERPC/NERPC
Validity of the Information From: 16/mm/yyyy To: 15/mm/yyyy
Date: dd/mm/yyyy

(Name of Hydro Electric Plant, Installed Capacity and Owner Organization)

S.No.	Title/Parameters	Values/Data/ Information
1	Number of Generating Units (e.g. 1 x 100 MW + 2 x 250 MW)	
2	Normative Auxiliary consumption (%)	
3	Type of Plant (RoR, Pondage or Reservoir)	
4	Installed Capacity of Unit (MW) - P	
5	Start time for each unit (Standstill to Synchronization of unit to grid) (in minutes)	
6	Which value (Cumecs/MW) is used for declaring MWh capability?	
7	Minimum load at which unit can stably run after synchronization - Unitwise (P1) (in MW)	
8	Forbidden zones or high cavitation zones - Unitwise (From MW to MW) - P2 to P3	
9	Maximum loading possible on unit (continuous) (P4)	
10	Unit-wise Cumecs/MW for P, P1,P2,P3 and P4 generation level as well as cumecs from standstill to synchronization.	
11	Maximum possible Ex-bus injection (MW) (including overload if any)	
12	Fixed Cost (paise / kWh upto one decimal place)	
13	Energy Charges (paise / kWh upto one decimal place) (for Section-62 plants)	
14	Compensation Charges (paise / kWh upto one decimal place) (for other than Section-62 plants)	
14	Ramp-Up Rate (MW/Min) for each unit	
15	Ramp-Down Rate (MW/Min) for each unit	
16	Requirement of Tandem Operation of the Plant (If Yes, with which plant and details and its Ratio)	
17	Present Governor Droop Setting (Unit-wise)	
S.No.	**Title/Parameters**	**Values/Data/ Information**

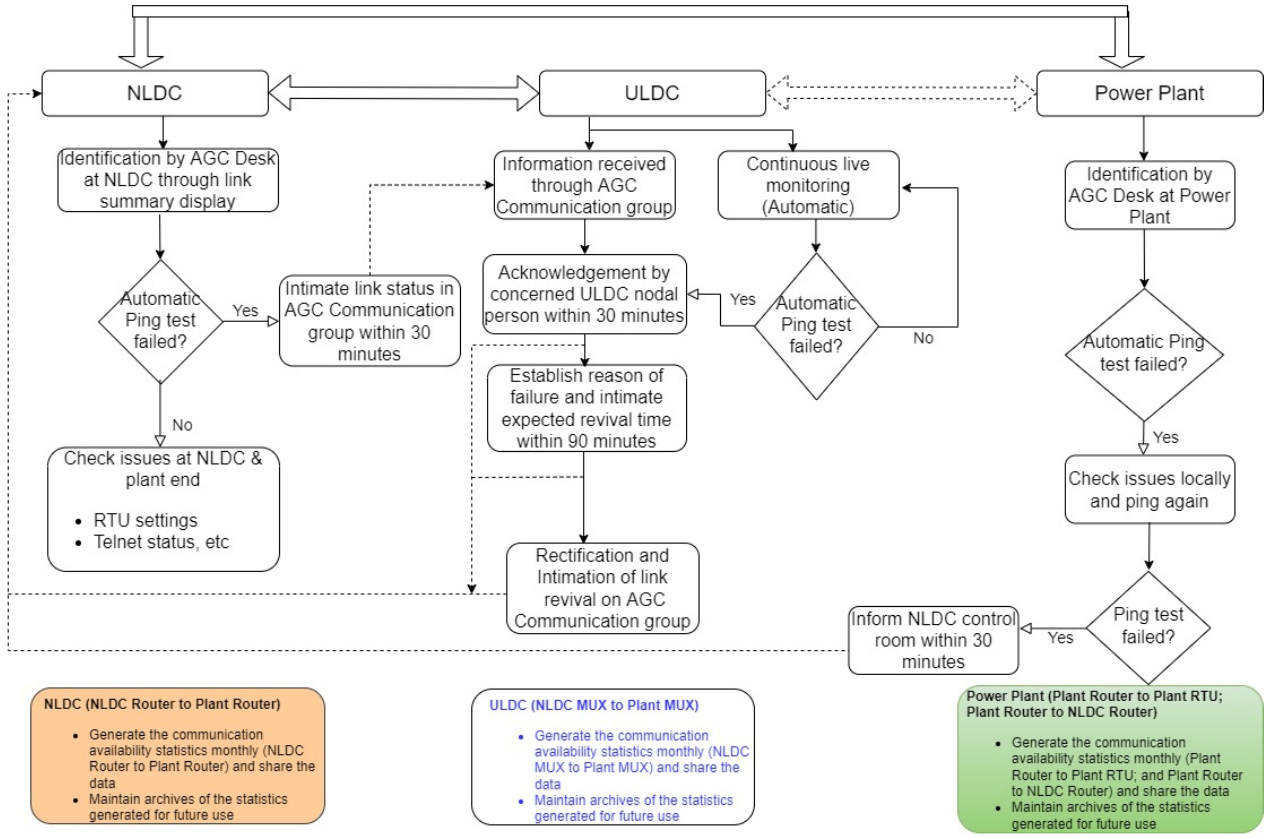
18	Considering all the constraints, how much further droop setting can be improved and range thereof	
19	Blackstart Facility availability (Yes/No)	
20	Any Other Information including the constraints (Time-specific, Location-Specific, Event Specific, Unit-Specific, etc.)	

Thermal Generator Details for Participation in Secondary Reserve Ancillary Service Provider (SRAS)		
From: (Name of SRAS Provider Generating Station) / (Name of Owner Organization)		
To: NRPC/WRPC/SRPC/ERPC/NERPC		
Format SRAS: Generator Details by SRAS Provider (Thermal/Gas)		
Validity of the Information **From:** 16/mm/yyyy **To**: 15/mm/yyyy		
Date: dd/mm/yyyy		
S.No.	**Title/Parameters**	**Values/Data**
1	Number of Generating Units (e.g. 1 x 210 MW + 2 x 500 MW)	
2	Total Installed Capacity (MW)	
3	Auxiliary consumption (%)	
4	Maximum possible Ex-bus injection (MW) (including overload if any)	
5	Technical Minimum (MW)	
6	Type of Fuel	
7	Region	
8	Bid area	
9	Fixed Cost (paise / kWh upto one decimal place)	
10	Energy Charges (paise / kWh upto one decimal place) (Section-62 plants)	
11	Compensation Charges (paise / kWh upto one decimal place) (other than Section-62 plants)	
12	Ramp-Up Rate (MW/Min) for each unit	
13	Ramp-Down Rate (MW/Min) for each unit	
S.No.	**Title/Parameters**	**Values/Data/ Information**

14	Start-up Time from Cold Start (in Min) & Warm Start of each unit	
15	Any other information	

Annexure-II: SOP for AGC Communication Providers

Standard Operating Procedure
for AGC Communication Failure Identification



Annexure-III: Open Loop and Closed Loop Testing Procedures

Open-Loop Test Procedure for

Power Plants under Automatic Control Generation (AGC)

Efficacy of the power plant model in the AGC software and the power plants response to AGC commands is first checked through Open Loop Testing (OLT). In the OLT, AGC software generates setpoint obeying all the limits and setpoint is also sent to the power plant. But, this AGC signal "DeltaP" is not fed to power plant DCS. Before start of the test, procedure for OLT is also circulated to the power plants which is given below.

1. Every signal in predefined signal list may be validated through verbal confirmation.
    a. Signal list may be kept ready by NLDC and Power plant before starting the process.
    b. Power plant executive to be present in control room with access to unit Digital Control System (DCS) and AGC Remote Terminal Unit (RTU) HMI
    c. NLDC executive to be monitoring AGC application
2. Simulate communication failure and check if Plant DeltaP analog becomes zero
    a. Power plant to create simulated communication failure (remove cable etc.)
    b. Power plant to correct the logic if DeltaP analog does not become zero
    c. NLDC to create simulated communication failure
    d. Power plant to correct the logic if DeltaP analog does not become zero
3. Simulate AGC Suspend status and check if Plant DeltaP analog becomes zero
    a. NLDC to create simulated AGC Suspend state
    b. Power Plant to correct the logic if DeltaP analog does not become zero
4. Toggle AGC from Remote to Local status and check if Plant DeltaP analog becomes zero
    a. Power Plant to create simulated Local and Remote states
    b. NLDC to concur change in Local and Remote states
    c. Power Plant to correct the logic if DeltaP analog does not become zero during Local state
5. Setup unit capability limits. For thermal plants, default limits shall be Max = unit's gross DC on bar. Min = 55% Max. Setup distribution factors. Default = (1/units on bar). For hydro plants P1 (min), P2 -P3 (forbidden zone) and P4 (max) may be checked.
    a. Power plant to test using maximum limit less than unit set point
        i. NLDC to check corresponding variation in DeltaP feedback signals
    b. Power plant to test using minimum limit more than unit set point
        i. NLDC to check corresponding variation in DeltaP feedback signals
    c. Change distribution factors and check if same is reflecting in NLDC
6. NLDC to explain the process for changing setting from 'Local' to 'Remote'. Note that before closed loop control, either keep the machine in 'dummy Remote' or in 'Local'.
    a. Local to Remote toggle is a manual process to be adopted by the power plant, only after code exchange with NLDC.
    b. Remote to Local can be done by the power plant without prior code exchange in case of emergency. But post-facto code exchange has to be done. For planned remote to local, code exchange is a must.
7. Account data verification (1-week process)
    i. Understand the account data format circulated to plants from NLDC

a. 5 min MWh, 15 min MWh

ii. Data may be sent to NLDC over email on daily basis for one week

iii. NLDC to verify that the account data archived at NLDC and received through mail from power plant are matching. Revert to power plant for corrections if needed.

8. Maintain max and min limits in unit DCS. Important before closed loop operation from plant safety perspective.

In addition to the plant max, min, ramp and other limits, response of the power plant to the AGC Suspend Status and communication failure signals are also checked in the OLT. To familiarize the power plants with the real time operations, code exchange drill can also be conducted. Dummy AGC accounts may be generated by both power plant (as per LDC format) and LDC. In case of any discrepancy, suitable actions like precision adjustment at power plant may be taken up.

Closed Loop Testing Procedure

Once the problems observed in open loop testing are addressed, Closed Loop Testing (CLT) is conducted with the power plant. In the CLT, AGC signal "DeltaP" is fed to power plant DCS and as a result the power plant is required to track 'AGC set point' instead of the power plant operator fed 'unit load set point'. Before the CLT, test procedure is circulated to the power plants which is given below,

1. Check all the Analog and Digital signals are updating correctly before the starting of the test. -------------- NLDC & Power plant
2. Maximum allowed variation above or below RULSP shall be set at 50 MW per power plant. ------------ NLDC
3. Maintain units in ‘Local’ mode ------------ Power plant
4. Inform RLDCs before the start of the test ------------NLDC
5. Alert ULDC / POWERGRID for ensuring uninterrupted communication. ---- ULDC, NLDC and Power plant.
6. Exchange of code between NLDC and Power plant for bringing units into ‘Remote’ --------- code by NLDC, code & action by Power plant
7. Allow the units to remain in ‘Remote’ un-interrupted for 45 minutes. Observe closely the variations of power plant. Power plants shall bear the deviations under DSM -------------- NLDC & Power plant
8. In case of any abnormal behaviour by AGC, the power plant is free to take the units into ‘Local’ without intimation. However, code may be exchanged subsequently with NLDC. ----------- Power plant
9. Simulate AGC Suspend status and check if individual unit DeltaP analog becomes zero ---- action by NLDC
10. Simulate communication failure and check if unit DeltaP analog becomes zero ---- action by NLDC
11. Toggle AGC from Remote to Local status and check if unit DeltaP analog becomes zero ---- action by Power plant.

Annexure-IV: Suggested Generic Hardware Specifications for AGC Connecting Equipment

The suggested hardware may be read together with the detailed signal list. Depending the on the number of units and signals required, the hardware requirement changes. Power plants/entities shall procure the hardware at their own cost considering the field level requirements.

a) Remote Terminal Unit (RTU) with a Main CPU Card, Communication Card with communication controller, DB 9 serial interface ports (101), minimum four Ethernet ports (104) interface Tx / Rx. Firmware of communication protocol should be loaded.

b) Analog input card: 32-bit processor with at least 32 analog inputs /outputs per generating unit, with scope for expansion.

c) Analog output card: 32-bit processor at least 16 analog outputs per generating unit, with scope for expansion.

d) Digital input card: 32-bit processor with at least 8 digital inputs per generating unit, with scope for expansion.

e) Digital output card: 32-bit processor with at least 4 digital output signals per generating unit, with scope for expansion. (Provision can be useful for connecting digital devices in future)

f) Shall be capable of communicating over IEC 60870-5-104 protocol with RLDC/NLDC. Should be capable of reporting to multiple masters (at least 4) simultaneously over IEC 104.

g) Shall have the capability of programing /parametrization, performing microprocessor level calculations and accepting logic. RAM/ flash memory may be capable of handling complex codes. (Arithmetic and logical operations like +, -, *, /, if, else, while, do, OR, AND, NOT, etc., would be needed)

h) Shall have the capability to acquire analog inputs of standard 4-20 mA current and 0-5 Vdc etc. or raise /lower command signals from AGC server / transducer etc.

h) Shall have GPS clock synchronisation facility as per the standard protocols.

i) Shall operate over the Standard DC input voltage of 24-60 V DC. Shall have the capability of automatic start up following restoration of power after an outage. Internal battery backup to hold data, date/time in SOE buffer memory is needed.

j) All Sequence of Events (SOE) shall be recorded and reported to RLDCs/NLDC.

k) Shall be capable of storing data on an external memory device.

l) Shall have communication interfaces via insert- able serial interface modules for Ethernet.

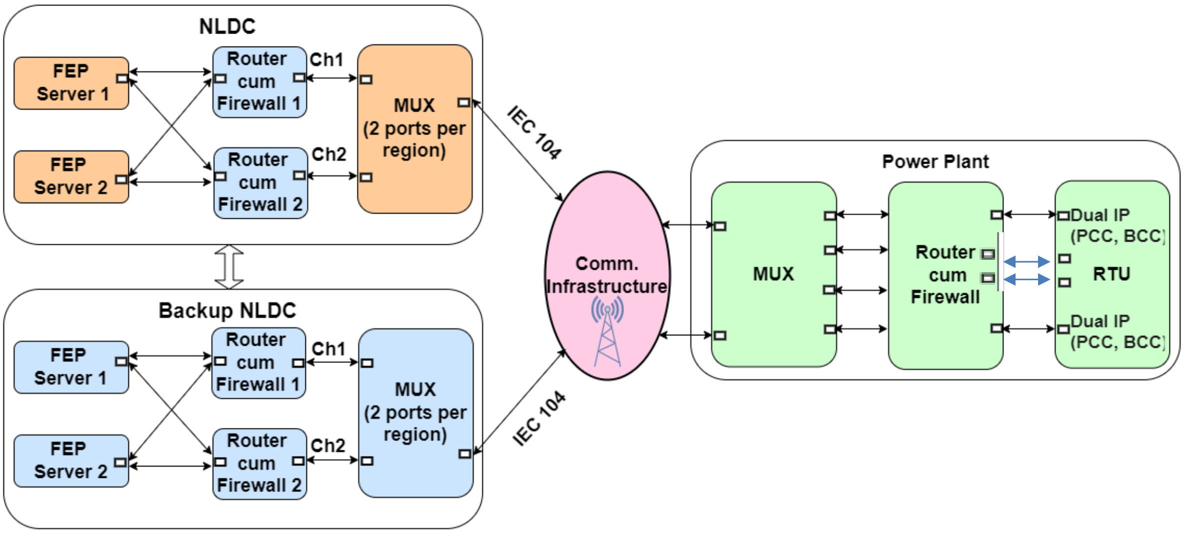
m) The associated system at power plants end shall be able to log / record the AGC signal / command from NLDC / RLDC (for the station before bifurcation) at an appropriate interval (say 2 sec or configurable) and shall integrate the AGC command over a period of 1 min, 5 min and 15 min period or user configurable period. The integrated value of AGC command will be stored in the data base with GPS time stamping.

n) Minimum two Line interface units (LIU), network switches along with ethernet ports, router cum firewall and patch cards, as per the assessment & requirement.

o) Optical fibre cabling (through redundant and alternate paths) from the nearest wideband node up to the unit /plant control room. Shall ensure necessary equipment at wide band node switch yard for interfacing with the available ports of CTU/POWERGRID. Shall include necessary accessories to achieve communication redundancy at RTU and switchyard.
q) PC and related software (Windows, MS Excel, Antivirus, etc.) for entering distribution factor as well as storing /logging the data as mentioned above.
r) Shall have the capability to assign a minimum of two IPs (dual IPs) to each ethernet port of the RTU.

A symbolic architecture is provided below.

AGC Communication Architecture



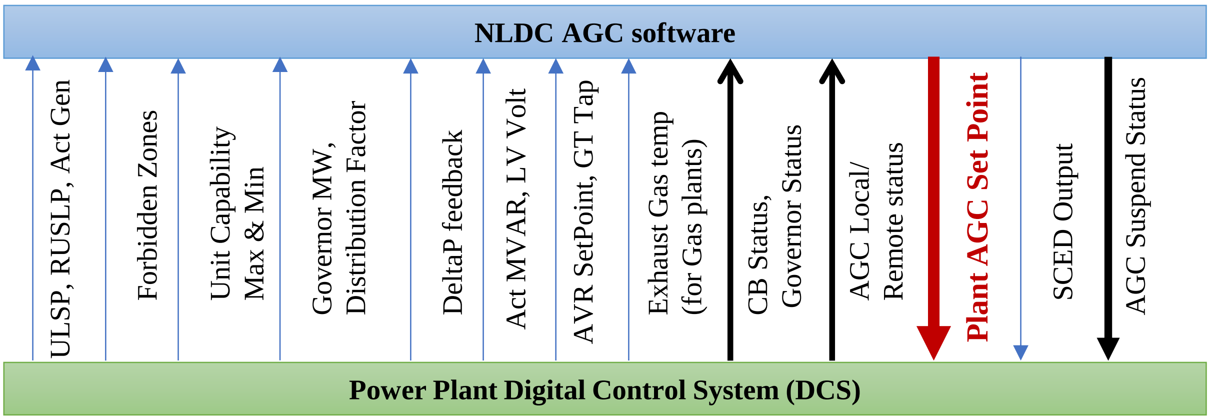
FEP: Front End Processor; SCADA application for interacting with RTUs for signal exchange
RTU: Remote Terminal Unit. AGC specific
MUX: Multiplexer
PCC: Primary Control Centre. NLDC; BCC: Backup Control Centre. Backup NLDC
IEC 104: IEC 60870-5-104 enables communication between control station and substation via a standard TCP/IP network.

Annexure-V: Detailed Signal Lists

Detailed Signal List for conventional generation

The following signals would be handled in AGC for control and monitoring purposes. Apart from the below mentioned signals, some other power plant specific signals also might be needed on a case-to-case basis. Expansion and spares included in procurement may be used for the same. Detailed logics to be implemented at each power plant and its individual generating units are given below.

Conventional Power Plant Signal List



A) Analog data to be sent from power plants to NLDC

1. **Unit Load Set Point (ULSP) MW** or Base Point

It is the unit-wise manual entry done by the plant shift engineer/operator in the digital control system (DCS) of the generating unit. ULSP is an ex-generating unit value entered by the power plant shift engineer in the DCS for each time block calculated by adding auxiliary power consumption of the unit to the ex-bus schedule provided by the RLDC. Note that the ex-bus schedule is provided for the total power plant by the RLDC; this is distributed in between the on bar generating units by the plant operator considering on-site constraints. To be entered for each individual unit.

2. **Ramp Limited Unit Load Set Point (RULSP)**

Ramp Limited Unit Load Set Point (RULSP) is the unit-wise continuous ramp rate limited signal produced based on the manual entry done by the plant shift engineer/operator in the digital control system (DCS) of the generating unit. RULSP is an ex-generating unit value derived from the ULSP entered by the power plant shift engineer in the DCS for each time block calculated by adding auxiliary power consumption of the unit to the ex-bus schedule provided by the RLDC. Typically, the ramp rate limitation for each unit is 1%*Installed Capacity/min of the unit.

3. Actual Generation MW

Actual generation in MW is the ex-generating unit value available in the DCS for every generating unit.

4. Cap_Max in MW

It is the ex-generating unit capability to be updated by the power plant operator by distributing the ex-bus declared capability amongst the on-bar generating units and adding the respective auxiliary consumption. This shall be entered by the power plant operator in the DCS / HMI. To be entered for each individual unit.

5. Cap_Min in MW

It is the minimum limit to be entered by the power plant operator in the DCS / HMI. To be entered for each individual unit.

Note: Cap_Max and Cap_Min values summed up for the total plant are used by the AGC software at NLDC to limit the final AGC Set Point before sending to the power plant. Cap_Max and Cap_Min are manually entered values (as decided during the October 2019 meetings with thermal power plants).

6. RGMO/FGMO/Governor input to governor

This signal is the MW input to the governor from the output of the RGMO control block in the DCS. Alternatively put, this signal in MW is the generation of the unit caused by primary frequency response alone.

7. Delta P feedback

Delta P feedback signal shall be taken from the DCS. In the unit DCS, Delta P (calculated in RTU or DCS) would be added to RULSP to calculate the final unit AGC set point. There can be limits enforced for each unit by the power plant to restrict the total MW load set point input reaching master control. Delta P feedback shall be calculated after the limits are enforced.

Delta P feedback = (Unit AGC Set Point after limits are enforced at unit – RULSP)

The reason "Unit AGC Set Point after limits are enforced at unit" is needed is to exactly capture the MW quantum reaching the master control of the unit after adding AGC input to RULSP. This signal would be used in accounting and verification of the data exchange between NLDC and power plant, and is critical.

8. Flexible DeltaP Limit (MW)

Flexible DeltaP Limit (F MW) has to be telemetered by the power plants to control centre, which ensures that the AGC SetPoint can only be in between (RULSP)+/- (F) MW. Power plants can change the limits manually as needed. This limit would be honored by the AGC software at LDC while sending AGC Set Point. This limit would be a MW value per unit each for up and down AGC regulation.

9. **Reactive Power Actual MVAR**

Actual MVAR reactive power absorbed or delivered by the unit.

10. **AVR Voltage Set Point**

Voltage set point of the automatic voltage regulator / exciter.

11. **Low Voltage (LV) side Actual Voltage**

Voltage at the LV side of the generating unit.

12. **Generator Transformer (GT) Tap Position**

Tap position setting of the generator transformer.

13. **Distribution Factor (fraction for distribution of AGC DeltaP in between the units of the power plant)**

It is the fraction by which the power plant operator divides the AGC regulation signal (Delta P = Plant AGC Set Point – Plant RULSP) in between the generating units. This signal is available in the user interface of the AGC remote terminal unit (RTU). The sum of all distribution factors of generating units in a power plant must be 1 (this feature can be automated or kept as manual entry).

Additional Analog inputs from Hydro power plants

14. **P1 in MW**

It is the minimum value after synchronization to be entered by the plant operator in the DCS/HMI. To be entered for each individual unit.

15. **P2 - P3 in MW (Forbidden zones or high cavitation zones)**

P2 – P3 is the forbidden zone / cavitation zone for all the Francis turbine based hydro power plants entered by the power plant operator in the DCS/HMI. To be entered for each individual unit.

16. P4 in MW

It is the MW value up to which a unit can be overloaded. To be entered by the plant operator in the DCS/HMI for each individual unit.

17. Declared Energy for the day in million units (MU)

18. Schedule Energy in MU (Cumulative for the day)

19. Water gross head (m)

Additional Analog inputs from Gas power plants

20. Reference exhaust gas temperature

21. Actual exhaust gas temperature

B) Digital Input data required per generating unit

1. Circuit Breaker Status on/off: To understand whether the unit is on bar or off bar. Ensuring the quality of this information is also very critical for AGC. This is a double point signal (2 - CB closed, 1 - CB open, 0 - in between)
2. Governor status on/off: To understand whether the unit is providing primary response also.
3. AGC Local/Remote:

   The manual choice to take the unit into local or remote is with the power plant shift engineer through DCS. A suitable user interface has been developed by the instrumentation team at every power plant for taking units into Local/Remote. This is a single-point digital signal (0 – Local, 1- Remote).

   "Remote" means unit Delta P shall be added to RULSP before processing the signal for maximum and minimum limits and further sending it to master control. Thus, if a unit is in Remote, it is ready to accept and respond to AGC signals. "Local" means unit Delta P shall not be added to RULSP. This choice can be because of onsite problems, non-readiness to accept AGC signals, prolonged communication failure, etc.

Additional Digital inputs from Hydro power plants

4. Pumping Status on/off: for pumped hydro power plants

C) Data sent from NLDC to Power plant

1. **AGC Set Point – Analog**

AGC set point shall be provided for the total power plant for thermal generating units. This AGC set point is the main input to the power plants from AGC which will be used for calculation of Plant Delta P = Plant AGC Set point – Plant RULSP.

- A feedback signal of AGC Set Point would be needed from the power plant to LDC through a separate address, called as Setter Feedback, which is used by AGC software as a handshake signal for control monitoring.

2. **AGC Suspend Status – Digital double point signal**

Sometimes AGC needs to be suspended by NLDC for reasons like intermittent communication, reboots, updations etc. This information would be sent as a digital status double point (2- means AGC not suspended, 1-means AGC suspended, 0-in between status)

- A feedback signal of AGC Suspend Status would be needed from the power plant to LDC through a separate address, called as Status Feedback, which is used by AGC software as a handshake signal for control monitoring.

3. **SCED schedule - Analog**

Real time ex-bus Net Schedule of the power plant would be provided by LDC to the power plants via AGC channel. The power plants may use this signal for monitoring/information purposes and not for control purposes as of now. This analog signal is the RLDC Net Ex-bus Schedule of the power plant including RTM, RRAS and SCED components.

- The feedback for the SCED signal shall be telemetered by the power plant to LDC through a separate address.

D) Basic logics to be implemented at the power plant RTU and DCS

The basic logics given below may be implemented for safe operation. Apart from these, some other logics may need to be implemented on case to case basis.

a) Plant DeltaP analog is calculated as, $Plant\ Delta\ P = (Plant\ AGC\ Set\ Point - \sum_1^n (ULSP_n)) * AGC\ Suspend\ Status * Communication\ Failure$

b) For Distribution Factor Analog Input of 'n'units, check $\sum_1^n (Distribution\ Factor_n)$ = 1

c) $Unit\ Delta\ P_n = \ Plant\ Delta\ P * Distribution\ Factor_n * \text{AGC Local Remote}_n$

d) $Unit\ AGC\ Set\ Point_n = Unit\ Delta\ P_n + ULSP_n$

e) Enforce minimum and maximum limits at each unit to process $Unit\ AGC\ Set\ Point_n$ and convert it to $Unit\ AGC\ Set\ Point\ after\ Limits_n$

f) $Unit\ Delta\ P\ Feedback_n = \ Unit\ AGC\ Set\ Point\ after\ Limits_n - ULSP_n$

g) Scheduled Energy (Cumulative MU) for Hydro is calculated as $\sum_{t=1}^{TB} (Scheduled\ MW/4000)$

Where TB is the current time block.

h) For hydro power plants, NLDC can send directly $Unit\ AGC\ Set\ Point_n$ for each unit. Hydro plant operator shall be provided with option to select one of the operating modes specified below:

- Plant AGC set point will be communicated from NLDC and use specified distribution factors for calculating unit Delta P as above.
- Unit AGC set points communicated from NLDC will be used for calculating unit Delta P
- Unit AGC set points communicated from NLDC be converted to Plant AGC set point and use specified distribution factors for calculating unit Delta P.

i) To detect communication failure and convert Plant DeltaP analog output to zero

j) To detect AGC Suspend status and convert Plant DeltaP analog output to zero

k) To detect AGC Local status and convert Plant DeltaP analog output to zero.

l) Automation of Distribution Factor, Cap_Max, Cap_Min and ULSP:

The actions while taking the units into Local, Remote, Shutdown, Communication failure, and AGC Suspending shall be automated. For the units which are on bar and in "Local", Cap_Max = Cap_Min = ULSP shall be done. Distribution Factor has to be changed accordingly. If CB is OFF, ULSP=0 has to be made for that unit. A new intermediate signal UADD may be configured. As many UADD signals may be derived for as many numbers of units.

UADD = (unit CB status ON,OFF) && (unit Local Remote status ON, OFF).

If either unit CB status=OFF or LR status=OFF, then UADD=0, else UADD=1.

An example table for a 3-unit plant is given below. The changes in Cap_Max, Cap_Min, Distribution Factor and ULSP may be automated based on the UADD state table.

	UADD				**Distribution factor**			**(Cap_Max, Cap_Min) Limits**		
S. No	**U 1**	**U 2**	**U 3**	**Logic**	**U 1**	**U 2**	**U 3**	**U1**	**U2**	**U3**
1	0	0	0	If U1ADD == 0 && U2ADD == 0 && U3ADD == 0	0	0	0	(ULSP, ULSP)	(ULSP, ULSP)	(ULSP, ULSP)
2	0	0	1	If U1ADD == 0 && U2ADD == 0 && U3ADD == 1	0	0	1	(ULSP, ULSP)	(ULSP, ULSP)	(Cap_Max, Cap_Min)
3	0	1	0	If U1ADD == 0 && U2ADD == 1 && U3ADD == 0	0	1	0	(ULSP, ULSP)	(Cap_Max, Cap_Min)	(ULSP, ULSP)
4	0	1	1	If U1ADD == 0 && U2ADD == 1 && U3ADD == 1	0	0.5	0.5	(ULSP, ULSP)	(Cap_Max, Cap_Min)	(Cap_Max, Cap_Min)
5	1	0	0	If U1ADD == 1 && U2ADD == 0 && U3ADD == 0	1	0	0	(Cap_Max, Cap_Min)	(ULSP, ULSP)	(ULSP, ULSP)
6	1	0	1	If U1ADD == 1 && U2ADD == 0 && U3ADD == 1	0.5	0	0.5	(Cap_Max, Cap_Min)	(ULSP, ULSP)	(Cap_Max, Cap_Min)

	UADD				Distribution factor			(Cap_Max, Cap_Min) Limits		
S. No	**U1**	**U2**	**U3**	**Logic**	**U1**	**U2**	**U3**	**U1**	**U2**	**U3**
7	1	1	0	If U1ADD == 1 && U2ADD == 1 && U3ADD == 0	0.5	0.5	0	(Cap_Max, Cap_Min)	(Cap_Max, Cap_Min)	(ULSP, ULSP)
8	1	1	1	If U1ADD == 1 && U2ADD == 1 && U3ADD == 1	0.33	0.33	0.33	(Cap_Max, Cap_Min)	(Cap_Max, Cap_Min)	(Cap_Max, Cap_Min)

m) Ramp limit on DeltaP

During the below status changes, DeltaP shall be made zero automatically.

a) Remote to Local

b) AGC Suspend OFF to ON

c) AGC communication Status ON to OFF

The movement of DeltaP to zero shall be restricted to 1%*Unit IC/min as the ramp rate limit in such cases.

Battery Energy Storage System (BESS) Signal List

Note: The architecture and signal list presented in this Annexure are provisional as sufficient experience of Solar AGC is yet to be obtained. In view of this, plants may note that spares, flexibility and last mile innovations may be needed during actual implementation.

a. Maximum MW permissible
It is the maximum MW which can be discharged (+ve value) / charged (-ve value) by the BESS at any particular point of time.

b. Minimum MW permissible
It is the minimum MW which can be discharged (+ve value) / charged (-ve value) by the BESS at any particular point of time.

c. Ramp rate up permissible
It is the maximum MW/min with which the BESS can be discharged (+ve value) by AGC at any particular point of time.

d. Ramp rate down permissible
It is the maximum MW/min with which the BESS can be charged (-ve value) by AGC at any particular point of time.

e. Actual MW
It is the actual generation MW value of the BESS.

f. Scheduled MW or ULSP
It is the scheduled generation value of the BESS, for fulfilling the stakeholder contracted energy/power. It is analogous to Unit Load Set-Point (ULSP) or RLDC schedule of a conventional power plant. Without Ancillary Services (SRAS and TRAS), BESS would discharge/charge this MW value. This Scheduled MW (ULSP) would be positive value while discharging, and negative value while charging.

g. Circuit Breaker status
To understand whether the BESS is on or off. Ensuring the quality of this information is also very critical for AGC. This is a double point signal (2 - CB closed, 1 - CB open, 0 - in between).

h. Local/Remote status
The manual choice to take the BESS into local or remote is with the plant shift engineer through DCS. A suitable user interface shall be developed by the instrumentation team at every plant for taking BESS into Local/Remote. This is a single-point digital signal (0 – Local, 1- Remote).

"Remote" means unit Delta P shall be added to RULSP before processing the signal for maximum and minimum limits and further sending it to master control. Thus, if a BESS is in Remote, it is ready to accept and respond to AGC signals. "Local" means block Delta P shall not be added to RULSP. This choice can be because of onsite problems, non-readiness to accept AGC signals, prolonged communication failure, etc.

i. Minimum State of Charge SOC % permissible

It is the minimum value of SOC % up to which a BESS can be discharged. Default value would be 10-20%.

j. Actual State of Charge SOC %

It is the current value of SOC % of the BESS. Beyond Maximum and Minimum SoC%, AGC software would stop sending AGC signals to BESS.

k. Scheduled Cycle (0-100%) count per day no.s

It is the number of round-trip cycles of BESS allowed per day. Default value would be 2-3 cycles/day.

l. Actual Cycle (0-100%) count per day no.s

It is the number of round-trip cycles of BESS exhausted at any point of time in the day, after 0000 hrs of that day. If the Actual Cycles count becomes equal to or greater than Scheduled Cycle count, then AGC software would stop sending AGC signals to BESS.

m. BESS forbidden zones

Information regarding any forbidden zones in which BESS should not be operated. This is analogous to the prohibited zones of Francis Hydro Turbines.

n. AGC Set Point MW from LDC to BESS

This is the signal from LDC to BESS, for the purpose of AGC control. This signal would contain the components of Scheduled MW and a correction corresponding to Area Control Error (ACE), and honours the limits mentioned above. The set point would be positive value while discharging, and negative value while charging.

The following signals would also be needed for monitoring purpose

o. Actual MVAR

p. Auxiliary Consumption MW

q. BESS Temperature

r. Ambient Temperature

s. Voltage (kV) at grid level

t. Voltage (V) at BESS LV side

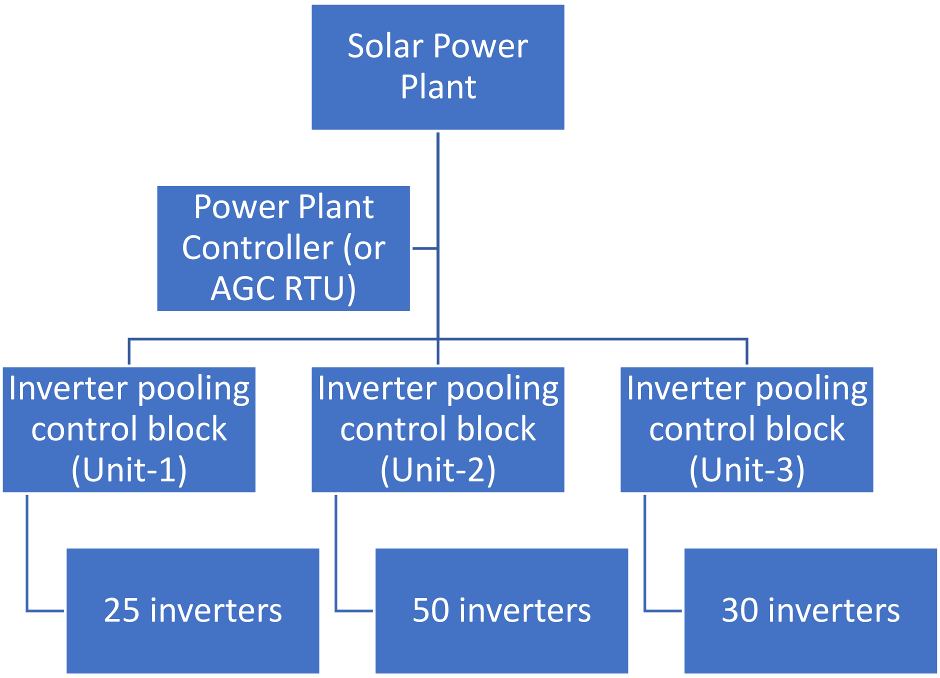
u. Feedback/handshake signals

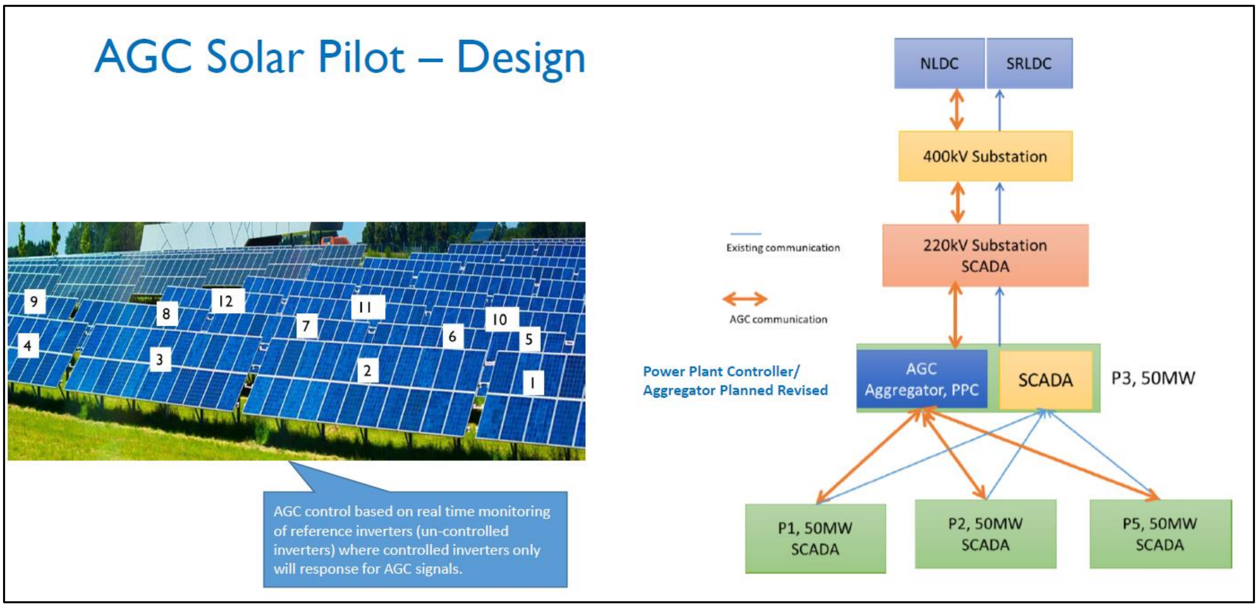
v. Primary Response MW

w. Primary Response ON/OFF status

x. Tap position

Solar Generators Signal List





Note: The architecture and signal list presented in this Annexure are provisional as sufficient experience of Solar AGC is yet to be obtained. In view of this, plants may note that spares, flexibility and last mile innovations may be needed during actual implementation.

A) Analog data to be sent from power plants to LDC per block

1. **ULSP MW:**
   It is a block-wise MW value calculated by assuming all the inverters as reference inverters. Thus, ULSP value is calculated block wise by adding the MPPT MW values of all the inverters in the block. Each block is analogous to a unit in the conventional power plant.

2. **Actual generation MW:**
   It is the block-wise actual generation value in MW.

3. **Reactive Power Actual MVAR**

   Actual MVAR reactive power absorbed or delivered by the block.

4. **Delta P feedback**

   Delta P feedback signal shall be taken from the DCS. In the block DCS, Delta P (calculated in RTU or DCS) would be added to ULSP to calculate the final block AGC set point. There can be limits enforced for each block by the power plant to restrict the total MW load set point input reaching master control. Delta P feedback shall be calculated after the limits are enforced.

   Delta P feedback = (Unit AGC Set Point after limits are enforced at block – ULSP)

   The reason "Unit AGC Set Point after limits are enforced at unit" is needed is to exactly capture the MW quantum reaching the master control of the unit after adding AGC input to ULSP. This signal would be used in accounting and verification of the data exchange between NLDC and solar generator, and is critical.

5. **Cap_Max in MW**

   It is the maximum limit of the block to be updated by the plant operator corresponding to the number of inverters in the block. This shall be entered by the plant operator in the DCS / HMI. To be entered for each individual block. This value can be the same as MPPT, by default.

6. **Cap_Min in MW**
   It is the minimum limit corresponding to the number of inverters in the block. To be entered by the power plant operator in the DCS / HMI for each individual block. This value can be 10%*MPPT, by default.

7. **Offset or Max Curtailment in MW**
   It is the maximum curtailment allowed for each block, entered by the plant operator. Percent curtailment of actual generation is to be converted to MW value, wherever conversion is needed. Default value can be 90%, converted to MW.

8. **Low Voltage (LV) side Actual Voltage in kV**

   Voltage at the LV side of each block.

9. **High Voltage (HV) side Actual Voltage in kV**

   Voltage at the HV side of each block.

10. **Reference Inverters Number**

    It is the number of reference inverters to be entered for each individual block. Percent reference inverters to be converted to number of reference inverters by the plant operator, wherever conversion is needed.

11. **Controllable Inverters Number**

    It is the number of controllable inverters to be entered for each individual block. Percent controllable inverters to be converted to number of controllable inverters by the plant operator, wherever conversion is needed.

12. **Reference Inverters MW**

    It is the block-wise MW value corresponding to the number of reference inverters.

13. **Controllable Inverters MW**

    It is the block-wise MW value corresponding to the number of controllable inverters.

14. **MPPT Loading in MW**

    It is the Maximum Power Point up to which a block can operate at any time. ULSP value is the same value as this, as of now. This signal is a spare signal considering the possible flexibility provisions in future RE scheduling.

B) Digital Input data required per block

1. Circuit Breaker Status on/off: To understand whether the block is on or off. Ensuring the quality of this information is also very critical for AGC. This is a double point signal (2 - CB closed, 1 - CB open, 0 - in between).

2. AGC Local/Remote:

   The manual choice to take the unit into local or remote is with the plant shift engineer through DCS. A suitable user interface shall be developed by the instrumentation team at every plant for taking blocks into Local/Remote. This is a single-point digital signal (0 – Local, 1- Remote).

   “Remote” means unit Delta P shall be added to ULSP before processing the signal for maximum and minimum limits and further sending it to master control. Thus, if a block is in Remote, it is ready to accept and respond to AGC signals. “Local” means block Delta P shall not be added to ULSP. This choice can be because of onsite problems, non-readiness to accept AGC signals, prolonged communication failure, etc.

3. Plant AGC Selection Mode:

   Input from Plant to LDC (to monitor) whether AGC is in Plant mode or Unit mode. In case the power plant has power plant controller, plant mode is convenient. Else, in cases where individual block controls are existing, Unit mode would be used on a case to case basis.

4. Plant Voltage Selection Mode:
   Input from Plant to LDC (to monitor) whether Plant is in Voltage Control mode or Power Factor mode

C) Data sent from LDC to Power plant

1. AGC Set Point – Analog

AGC set point shall be provided for the total power plant for thermal generating units. This AGC set point is the main input to the power plants from AGC which will be used for calculation of Plant Delta P = Plant AGC Set point – Plant ULSP.

2. AGC Suspend Status – Digital double point signal

Sometimes AGC needs to be suspended by LDC for reasons like intermittent communication, reboots, updations etc. This information would be sent as a digital status double point (2- means AGC not suspended, 1-means AGC suspended, 0-in between status)

Annexure-VI: Guideline for Calculation and Monitoring of Area Control Error (ACE)

National Load Despatch Centre
Power System Operation Corporation Limited

Guideline for Calculation and Monitoring of Area Control Error

This document provides the detailed guidelines to be uniformly adopted by the NLDC, RLDCs, SLDCs, and REMCs for measurement, calculation, monitoring, and archival of Frequency, Tie-Line Flows, Frequency Bias, Metering Errors, and Area Control Error (ACE). ACE is an important parameter which depicts the health of the power system. This document enables uniform notation for ACE, thereby allowing all the load despatch control rooms pan India to pass on information about this grid security aspect with one another.

Table of the Contents

1. Formula of Area Control Error (ACE)

The Area Control Error (ACE) for each control area[1] would be calculated at all the load despatch centres based on telemetered values and external inputs as per the below formula[2].

$$\mathbf{ACE = (Ia - Is) - 10 * Bf * (Fa - Fs) + Offset}$$

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

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

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

Fa = Actual system frequency in Hz

Fs = Schedule system frequency in Hz (default 50 Hz)

Offset = Provision for compensating errors such as measurement error; default value zero.

In the above formula, ACE has three components as below.

1. Interchange deviation component **(Ia-Is)**
2. Frequency deviation component **-10*Bf*(Fa-Fs)**
3. Offset or Metering Error

Sign convention adopted for interchange MW values is, positive value for export and negative value for import. Bf is a negative value. System Frequency (Fa) is a positive value, close to the National Reference Frequency[3] of 50 Hz.

ACE is positive means that the control area has surplus generation and the control area's internal generation has to be backed down. ACE is negative means the control area is in deficit and the control area's internal generation has to be increased. ACE has to be driven towards zero for better frequency control and grid security.

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[1] *Control Area means an electrical system bounded by interconnections (tie lines), metering and telemetry which controls its generation and/or load to maintain its interchange schedule with other control areas and contributes to regulation of frequency as specified;*
Definition from the Report of the Expert Group: Review of Indian Electricity Grid Code, January 2020. https://cercind.gov.in/2020/reports/Final%20Report%20dated%2014.1.2020.pdf

[2] Formula as given in the Report of the Expert Group: Review of Indian Electricity Grid Code, January 2020.

[3] Defined in the Report of the Expert Group: Review of Indian Electricity Grid Code, January 2020.

2. Measurement of Frequency

System frequency is an important input for calculating ACE. Typically, ACE is used for taking generation increase/decrease actions using the below applications

a. Secondary frequency control through AGC
b. Tertiary frequency control through TRAS
c. Monitoring and manual generation rescheduling

All the above three applications operate in the time frame of a few seconds to several minutes. Hence it should suffice that the system frequency signal is captured using a sampling time of a few seconds for calculation of ACE.

Suggested sampling time for frequency: 4 seconds, i.e., take a fresh frequency data point every four seconds.

2.1. Choosing the master list of redundant frequency sources

The frequency signal taken should be free from noise. To ensure the same, the signals from such stations shall be selected as the frequency sources, whose historical data is proven to be at least 99.9% noise-free in the past three months. To identify noise, the frequency data of different stations shall be plotted in a time series graph. The graph should be free from spikes. Choose 10 such stations to act as redundant frequency sources in ACE calculation. This list may be reviewed quarterly.

2.2. Location of redundant frequency sources and host server

For the applications a, b, and c, mentioned above, frequency source from any geographic location should serve the purpose as the time range of interest is in seconds. Typically, in time frame of a few seconds, all the electromagnetic transients and most of the electromechanical transients usually get damped and settled[4]. Hence, stations from different geographic locations can be chosen as redundant frequency sources. Having a mix of at least 10 redundant frequency sources from SCADA and URTDSM (PMU) is advised. Frequency data from URTDSM server are generally imported into SCADA[5] for the purpose of ACE calculation.

2.3. Algorithm for selecting the Primary Frequency Source

The ACE calculation program can look at the quality tags of all the redundant signals and choose one of the signals as the primary source. The update of the

[4] For applications b & c, as the dispatches are time block-wise, there is no need of consideration about frequency oscillations. For AGC, oscillations in ACE are further smoothened by the exponential moving average filters and the PI controller (low pass filter) which are typically part of the AGC software. The integration time in AGC is in generally between 10s -120s and hence the electromechanical oscillations and any noise get further damped.

[5] PMUs are not available on all the tie-lines. Hence calculating ACE is recommended through SCADA.

quality tags happens along with the sampling of the data in the EMS system, as a general practice. In case the quality of the primary frequency source becomes 'suspect', then the next signal with 'good quality tag' shall be selected as the primary frequency source automatically. This logic may be developed into the calculation program gradually, if not immediately.

Algorithm outline:

Initialize Primary Freq= 50 Hz

Initialize K=1

Initialize J=1

Initialize Flag = Good

Call Subroutine-A

Subroutine-A ()

    Select the Kth frequency signal in the list as 'primary' and read its quality tag.

    If the quality tag is good, set J=1, exit Subroutine-A and GOTO Subroutine-B.

    If, J=11, Primary Freq = 50 Hz, exit Subroutine-A and GOTO Subroutine-B.

    Else, K=K+1, J=J+1 and Call Subroutine-A.

End Subroutine-A ()

Subroutine-B ()

    While Flag = Good

        Read the quality tag of the Kth signal at time t

        If the quality tag is good, t=t0+4s, Flag=Good

        Else Flag = Bad

    End While

GOTO Subroutine-A

End Subroutine-B

3. Measurement of Tie-Line Flows

3.1. Actual Tie-Line Flows

Actual tie-line flows shall be sampled every 4 seconds[6] similar to frequency and shall be used in the ACE calculation. The update of the quality tags happens along with the sampling of the data in the EMS system, as a general practice. Say, the data is acquired only every 12s by the SCADA because of delays[7], the ACE calculation program shall repeat the data thrice in those 12s. Some Tie-Line flows have the problem of becoming suspect often. Such data should be identified and rectified immediately by following up with site/substation. It shall be ensured that the clock synchronization across all the stations taken into consideration by the respective LDC and its calibration shall be done once every year in order to ensure the synchronicity of time stamping of the collected data. Every tie-line flow can be obtained from 3 different sources viz.,

i. Primary Side (choose the Metering End as per IEGC)
ii. Secondary Side (side other than the Metering End as per IEGC)
iii. State Estimator output

Primary side data shall be normally used for ACE calculation. In case the quality of the primary side becomes 'suspect', then let the ACE calculation program automatically choose the secondary side. If flow at both the ends goes suspect, use the state estimator output. If the state estimator is not running, replace the suspect data manually with 'last good value', rather than retaining garbage value. Information of manual interventions shall be monitored, carried forward and updated frequently in every shift. Sign convention adopted for interchange MW values is, positive value for export and negative value for import.

Note that all the tie-lines should be accounted for, while calculating the Net Actual Tie-Line Flow (Ia), i.e., algebraic sum of the flows. If any of the tie-lines is non-observable, the data of the same can be replaced with a fixed value as informed by site/substation telephonically to the control room.

3.2. Scheduled Tie-Line Flows

The Net Scheduled Tie-Line Flow (*Is*) of a control area should generally be the output of a scheduling software program, from which the data is imported into SCADA for all the 96-time blocks. ACE is calculated using the net tie-line flow, and path-wise scheduled flows are algebraically added based on direction.

[6] At NLDC, the tie line flow acquisition delay (around 10s) includes the delay introduced while acquiring data from RLDCs through ICCP, apart from the delay in acquiring tie line data from RTUs to the RLDCs. For other RLDCs/control areas, delay (~ 5s) is mainly introduced in acquiring tie line data from RTUs to the RLDCs. However, this data acquisition timing has to be improved further by all the control areas.

[7] Higher updation time as well as non-simultaneity can lead to inconsistent frequency response assessment and incorrect ACE calculations. Ideal would be to have PMUs on all inter-regional lines to begin with, followed by all inter-state tie lines.

Net Scheduled Tie-Line Flow of the control area can be calculated every time block by adding the algebraic sum of scheduled MW export contracts (from the control area to all the other control areas; positive values) and the scheduled MW import contracts (to the control area from all the other control areas; negative values) and the MW sum of resultant of the virtual entities. In line with the tie-line flow convention, sign convention for TRAS Up regulation is positive, TRAS Down is negative. Note that for ACE calculation, we are interested in the net control area values, and not the path-wise values.

For example, if a particular control area imports 2000 MW from the other control areas through tie-lines, exports 500 MW to the other control areas through tie-lines, TRAS Up of 200 MW is dispatched and SCED Down of 100 MW is dispatched. Then Is = -2000+500+200-100 = -1400 MW for that time block.

Note that the Net Scheduled Tie-Line Flow value shall be always less than the Export Available Transfer Capability (ATC) and greater than the Import ATC value. While calculating ACE, this 15-minute data has to be updated/refreshed every 4 seconds.

4. Assessment of Frequency Bias

The 2017 IEEE Task Force Report[8] on “Measurement, Monitoring, and Reliability Issues Related to Primary Governing Frequency Response,” recommends using Frequency Response Characteristic (FRC) calculated after the power and frequency transients have settled, for the Frequency Bias Coefficient (Bf) used in the ACE equation. A sample size of twenty (20) FRC events has been deemed adequate for estimating the frequency response characteristic to rule out human error. Several other references[9] also have been studied, which support the IEEE Task Force Report recommendations.

[8] IEEE Task Force Report. 2017. “Measurement, Monitoring, and Reliability Issues Related to Primary Governing Frequency Response,” Technical Report PES-R-24, October. https://resourcecenter.ieee-pes.org/publications/technical-reports/PESTECRPTGS0001.html

[9] J. L. Willems, "Sensitivity Analysis of the Optimum Performance of Conventional Load-Frequency Control," in IEEE Transactions on Power Apparatus and Systems, vol. PAS-93, no. 5, pp. 1287-1291, Sept. 1974, doi: 10.1109/TPAS.1974.293852. https://ieeexplore.ieee.org/document/4075491

NERC, Frequency Response Standard Background Document. November, 2012. https://www.nerc.com/pa/Stand/Project%20200712%20Frequency%20Response%20DL/Bal-003-1-Background_Document-Clean-2013_FILING.pdf

P. Kundur, Power System Stability and Control, Chapter 11, McGraw-Hill, New York, 1994.

FRC computation procedure has been clearly provided in the draft IEGC 2020[10]. A sample template for FRC assessment is enclosed as Annexure-I.I. FRC shall be computed for every control area for all events involving a sudden 1000 MW or more load/generation loss or a step change in frequency by 0.10 Hz. All these FRC values shall be archived along with date, time and reasons of the event.

4.1. Bf value assessment

In the calculation of ACE, the value of Frequency Bias Coefficient in MW/0.1 Hz (negative value) shall be based on median Frequency Response Characteristic. Median[11] value of the past 20 events would be used for updating the FRC. The occurrence of these 20 events is actually expected to cover the entire previous year, thereby subsuming the seasonality aspect of load and generation. Bf value shall be declared by the Nodal Agency.

4.2. Bf update timing

The Bias (Bf) value may be updated in the ACE calculations at the LDCs, once in every quarter on the 24th day of the month after the completion of the previous quarter. The literature studied and mentioned in the footnotes-6,7 suggests updating the bias values once in a year for practical power systems. However, due to the developing nature of Indian power system, a quarterly update has been suggested. For example, update the Bias (Bf) value on 25th July, after the completion of the quarter April – June. The updated Bf value in SCADA shall also be shared continuously through ICCP bottoms up, from SLDCs to RLDCs, and from RLDCs to NLDC for all the relevant control areas. An offline all India compilation in Excel/DB may be maintained by NLDC for all the control areas. While calculating ACE, this quarterly data has to be updated/refreshed every 4 seconds.

5. Measurement of Metering Errors - OFFSET

Typically, the accuracy level of the SCADA Remote Terminal Unit (RTU) is 0.5%. Also, there is a chance of error in the instrumentation and communication. Inherent latency and non-simultaneous reporting of SCADA might also cause metering error. Hence, while calculating ACE using the RTU metered tie-line flows, there is a probability of metering errors corrupting the actual value. OFFSET shall be used if such a metering error has been established using long-term data/statistical analysis.

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[10] Report of the Expert Group: Review of Indian Electricity Grid Code, January 2020. https://cercind.gov.in/2020/reports/Final%20Report%20dated%2014.1.2020.pdf

[11] The median is a better choice as the FRC value is susceptible to a small number of extreme values, or outliers. These outliers are possible when incorrect information regarding the exact quantum of load/generation lost in the control area is received for an FRC event.

In case of un-observable tie-line flows, where it is not feasible to replace the actual tie line flow data manually, OFFSET can be used to substitute the tie-line flow with correct sign convention. Information of manual interventions shall be monitored, carried forward and updated frequently in every shift. Sign convention adopted for interchange MW values is, positive value for export and negative value for import. While calculating ACE, OFFSET data has to be updated/refreshed every 4 seconds.

6. Calculation of ACE

Scheduled Interchange (Is), Actual Interchange (Ia), Actual Frequency (Fa), Scheduled Frequency (Fs), Frequency Bias (Bf) and Offset shall be updated/refreshed every 4 seconds in the calculation. The formula, techniques and details have already been mentioned in the earlier sections. With the above data, ACE may be calculated every 4 seconds, i.e., refresh the value of ACE every 4 seconds.

7. Archival of different parameters

It is important to archive the individual parts of the ACE into a database every 4 seconds. That means, apart from the calculated ACE, Interchange deviation (Ia-Is), Frequency deviation (Fa-Fs), Frequency Bias (Bf) and Offset shall also be separately archived in the database every 4 seconds. This is necessary to build and calculate what-if scenarios for reserve estimation, forecasting, etc.

8. Monitoring of ACE and Suggested Corrective Actions

All the control rooms of the control areas shall prominently monitor ACE, apart from the tie-line deviation and frequency deviation.

ACE is positive means that the control area has surplus generation and the control area's internal generation has to be backed down. ACE is negative means the control area is in deficit and the control area's internal generation has to be increased. All the frequency control interventions shall be in the direction to drive ACE towards zero. ACE remaining in the same direction for several minutes without crossing zero is a strong indicator that the frequency control interventions have to be kicked in.

9. Calculating ACE for Regional Entity Control Area

Each Regional entity power station is a control area by itself. ACE for a regional entity power plant can also be worked out separately for the purpose of monitoring. The bias would depend on the number of units on bar (40% of capacity on bar per Hz assuming 5% droop plus a small load response from the unit auxiliaries). When there are fragmented control areas and virtual power plants operated from a single control center, this aspect assumes importance.

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<u>Annexure –VII: Standard Operation Guidelines for Power Plants under SRAS</u>

Operations Guideline for Coal Based Power Plants under SRAS

Revision 0, Issued: 05th December 2022

This document provides the standard operating procedures to be followed during the continuous operation of the power plants under Automatic Generation Control (AGC) and attempts to answer the frequently asked questions.

Revision History

Rev 0 : Original document – 05th Dec 2022

1. Controls Available with the Power Plant during AGC

User data entry of the below parameters is available for all the power plants under AGC. This data is received directly by NLDC from the power plants. Data can be entered through the relevant field in the user interface of the Remote Terminal Unit (RTU) or Digital Control System (DCS). These below five signals are the "controls" available with the power plant during AGC operation.

1.1. Unit Load Set Point (ULSP) in MW

ULSP is the unit-wise manual entry done by the plant shift engineer/operator in the digital control system (DCS) of the generating unit. ULSP is a gross value entered by the power plant shift engineer in the DCS for each time block calculated by adding auxiliary power consumption of the unit to the ex-bus schedule provided by the RLDC. Note that the ex-bus schedule is provided for the total power plant by the RLDC; this is distributed in between the on bar generating units by the plant operator considering on-site constraints. To be entered for each individual unit.

1.2. Ramp Limited Unit Load Set Point (RULSP) in MW

RULSP is the unit-wise continuous ramp rate limited signal produced based on the manual ULSP entry done by the plant shift engineer/operator in the digital control system (DCS) of the generating unit. ULSP is filtered through a ramp rate filter, so that the step changes in ULSP are limited by the ramp rate and the resulting RULSP is a smooth ramp limited signal. Typically, the ramp rate limitation for each unit is 1%*Installed Capacity/min of the unit. RULSP is the signal that would be used by the NLDC AGC software as the basepoint for generating the AGC Set Point.

1.3. Cap_Max in MW

It is the gross unit capability to be updated by the power plant operator by distributing the ex-bus declared capability amongst the on-bar generating units and adding the respective auxiliary consumption. This shall be entered by the power plant operator in the DCS / HMI. To be entered for each individual unit. Any changes to the Cap_Max shall be carried out after giving prior intimation to the Nodal Agency.

1.4. Cap_Min in MW

It is the minimum limit to be entered by the power plant operator in the DCS / HMI. The value of Cap_Min would normally be 55%*(Cap_Max). To be entered for each individual unit. Any changes to the Cap_Min shall be carried out after giving prior intimation to the Nodal Agency.

Note: Cap_Max and Cap_Min values summed up for the total plant are used by the AGC software at NLDC to limit the final AGC Set Point before sending to the power plant. Cap_Max and Cap_Min are manually entered values (as decided during the October 2019 meetings with thermal power plants).

1.5. Distribution Factor

It is the fraction by which the power plant operator divides the AGC regulation signal (Delta P = Plant AGC Set Point – Plant ULSP) in between the generating units. This signal is available in the user interface of the AGC remote terminal unit (RTU). The sum of all distribution factors of generating units in a power plant must be 1 (this feature shall be automated by the power plant as per the detailed signal list). For achieving maximum economy, it is advisable to divide distribution factor equally between units operating under AGC Remote.

1.6. AGC Local/Remote

AGC Remote is the desired mode of operation for a SRAS Provider. However, during forced outages, SRAS Provider may take the units into Local after exchanging code with NLDC with an appropriate reason.A suitable user interface shall be developed by the instrumentation team at every power plant for taking units into Local/Remote. This is a single-point digital signal (0 – Local, 1- Remote). "Remote" means unit Delta P shall be added to RULSP before processing the signal for maximum and minimum limits and further sending it to master control. Thus, if a unit is in Remote, it is ready to accept and respond to AGC signals. "Local" means unit Delta P shall not be added to RULSP.

2. Activity list for different use cases

The actions while taking the units into Local, Remote, Shutdown, Communication failure, and AGC Suspending shall be automated as per the detailed signal list. For the units which are on bar and in "Local", Cap_Max = Cap_Min = ULSP shall be done. Distribution Factor shall be made zero for units which are in "Local". If CB is OFF, ULSP=0 shall be made for that unit. A new intermediate signal UADD may be configured. As many UADD signals may be derived for as many numbers of units.

UADD = (unit CB status ON,OFF) && (unit Local Remote status ON, OFF).

If either unit CB status=OFF or LR status=OFF, then UADD=0, else UADD=1.

An example table for a 3-unit plant is given below. The changes in Cap_Max, Cap_Min, Distribution Factor and ULSP may be automated based on the UADD state table.

	UADD				Distribution factor			(Cap_Max, Cap_Min) Limits		
S. No	U 1	U 2	U 3	Logic	U 1	U 2	U 3	U1	U2	U3
1	0	0	0	If U1ADD == 0 && U2ADD == 0 && U3ADD == 0	0	0	0	(ULSP, ULSP)	(ULSP, ULSP)	(ULSP,ULSP)
2	0	0	1	If U1ADD == 0 && U2ADD == 0 && U3ADD == 1	0	0	1	(ULSP, ULSP)	(ULSP, ULSP)	(Cap_Max, Cap_Min)
3	0	1	0	If U1ADD == 0 && U2ADD == 1 && U3ADD == 0	0	1	0	(ULSP, ULSP)	(Cap_Max, Cap_Min)	(ULSP,ULSP)
4	0	1	1	If U1ADD == 0 && U2ADD == 1 && U3ADD == 1	0	0.5	0.5	(ULSP, ULSP)	(Cap_Max, Cap_Min)	(Cap_Max, Cap_Min)
5	1	0	0	If U1ADD == 1 && U2ADD == 0 && U3ADD == 0	1	0	0	(Cap_Max,	(ULSP, ULSP)	(ULSP,ULSP)

	UADD				Distribution factor			(Cap_Max, Cap_Min) Limits		
S.No	U1	U2	U3	Logic	U1	U2	U3	U1	U2	U3
								Cap_Min)		
6	1	0	1	If U1ADD == 1 && U2ADD == 0 && U3ADD == 1	0.5	0	0.5	(Cap_Max, Cap_Min)	(ULSP, ULSP)	(Cap_Max, Cap_Min)
7	1	1	0	If U1ADD == 1 && U2ADD == 1 && U3ADD == 0	0.5	0.5	0	(Cap_Max, Cap_Min)	(Cap_Max, Cap_Min)	(ULSP,ULSP)
8	1	1	1	If U1ADD == 1 && U2ADD == 1 && U3ADD == 1	0.33	0.33	0.33	(Cap_Max, Cap_Min)	(Cap_Max, Cap_Min)	(Cap_Max, Cap_Min)

Note:

1. Power plants shall not place any limits on DeltaP per unit at their end. Note that imposing any limits on DeltaP will adversely impact power plant performance metrics during post-dispatch evaluation. Restriction on DeltaP can also cause ramp violations during ULSP changes by the power plant.

2. Always ensure that the ULSP value is in between Cap_Max and Cap_Min.

2.1. To take a generating unit into Remote

a) Make Distribution Factor = 0 for the units which are in Local.
b) Make Cap_Max = Cap_Min=ULSP for the units which are in Local.
c) Make ULSP = Cap_Max = Cap_Min = Distribution Factor =0, for all the off-bar units.
d) Make sure to distribute Distribution Factor on the units under Remote. Ensure that the sum is 1.
e) Check if Cap_Max and Cap_Min are entered as desired.
f) Exchange code with NLDC. Maintain separate AGC codebook.
g) Always ensure that the ULSP value is in between Cap_Max and Cap_Min.

2.2. To take a generating unit into Local

a. Exchange code with NLDC (given as Figure 1 below). Maintain separate AGC code book.
    - If the reason is a planned one, inform in advance
    - If the reason is emergency, inform post facto

- If the reason is automatic local, then inform post facto

b. Make Distribution Factor = 0 for the units which are in Local.
c. Make Cap_Max = Cap_Min=ULSP for the units which are in Local.
d. Make sure to re-distribute Distribution Factor on the remaining units under Remote. Ensure that the sum is 1.

Date	Time	AREA AGC STATUS	NLDC CODE	POWER PLANT CODE	LOCAL/REMOTE		UNIT NO	REQUESTED BY (PLANT/NLDC)	CODE EXECUTION TIME	REMARKS	SIGN
					FROM	TO					

AGC Code book format

2.3. When a generating unit trips or is taken under shutdown, and the unit has been under Remote

a. Exchange code with NLDC for taking the unit into Local.
   - If the reason is a planned one, inform in advance
   - If the reason is emergency, inform post facto

b. Make Distribution Factor=0 for units which are in Local. Make sure to re-distribute Distribution Factor on the remaining units under Remote. Ensure that the sum is 1. For example, if the DF is 0.2 each for 5 units under Remote, and the fifth unit tripped, then DF will be 0 for the fifth unit and will be 0.25 for the remaining four units.
c. Make Cap_Max=0 for the tripped unit
d. Make Cap_Min=0 for the tripped unit
e. Make ULSP=0 for the tripped unit
f. Make sure that the CB status is being telemetered correctly as "Open =1"

2.4. There are three generating units; the first unit is off bar (RSD), the second unit is in Remote, and the third unit is in Local (for PG tests)

a. Distribution Factor = 0 for first and third units
b. Distribution Factor = 1 for second unit
c. Make Cap_Max=0 for off bar unit (only for first unit)
d. Make Cap_Min=0 for off bar unit (only for first unit)
e. Make ULSP = 0 for off bar unit (only for first unit)
f. Make Cap_Max = Cap_Min=USLP, for the units which are in Local (only for third unit).
g. Must telemeter Cap_Max, Cap_Min, and ULSP for the second and third units

2.5. What to do after detecting Communication Failure / Communication Fluctuation.

a. Check ping status between plant router and plant RTU. If ping test fails, check for local issues at the end plant. Observe that DeltaP automatically becomes zero.
b. If ping test is through, inform NLDC for follow-up..

c. In case communication failure persists and/fluctuating, exchange code with NLDC and take units into Local.
d. After communication disruption is verified as rectified, then exchange code with NLDC and take units into Remote.

2.6. How to synchronize a new unit, while other units are running under AGC Remote in a power plant?

a. Before starting the unit
    i. Force CB status to "Open", for that unit.
    ii. Force Cap_Max = Cap_Min = ULSP = Distribution Factor = 0, for that unit.
b. Start the unit and synchronize the unit. Maintain CB status as forced to "Open=1".
c. After the unit has reached technical minimum
    i. Make Cap_Max = Cap_Min = ULSP. Release CB status to "Closed=2".
    ii. To take this unit into Remote, follow section 2.1, as usual.

2.7. How to take a unit under planned outage, while other units are running under AGC Remote in a power plant?

a. Before ramping down the unit for planned outage,
    i. Force CB status to "Open=1", for that unit.
    ii. Force Cap_Max = Cap_Min = ULSP = Distribution Factor = 0, for that unit.
    iii. Make sure to re-distribute Distribution Factor on the remaining units under Remote.
b. Exchange code with NLDC for taking the selected unit into Local.
c. Ramp down the unit and take the unit into outage.

Operations Guideline for Gas Based Power Plants under SRAS

Revision 0, Issued: 05th December 2022

This document provides the standard operating procedures to be followed during the continuous operation of the power plants under Automatic Generation Control (AGC) and attempts to answer the frequently asked questions.

Revision History

Rev-0 : Original document – 05th Dec 2022

1. Controls Available with the Power Plant during AGC

GT refers to the Gas Turbine and ST refers to the Steam Turbine. It is important to note that in the combined cycle power plants, AGC controls only the GTs. STs can operate in tandem to the GTs in combined cycle operation. The MWh generated by both GTs and STs will be compensated.

User data entry of the below parameters is available for all the power plants under AGC. This data is received directly by NLDC from the power plants. Data can be entered through the relevant field in the user interface of the Remote Terminal Unit (RTU) or Digital Control System (DCS). These below signals are the "controls" available with the power plant during AGC operation.

1.1. Unit Load Set Point (ULSP) in MW

ULSP is the unit-wise manual entry done by the plant shift engineer/operator in the digital control system (DCS) of the GTs. ULSP is a gross value entered by the power plant shift engineer in the DCS for each time block calculated by adding auxiliary power consumption of the unit to the ex-bus schedule provided by the RLDC. Note that the ex-bus schedule is provided for the total power plant by the RLDC; this is distributed in between the on bar GTs by the plant operator considering on-site constraints. To be entered for each GT.

1.2. Ramp Limited Unit Load Set Point (RULSP) in MW

RULSP is the unit-wise continuous ramp rate limited signal produced based on the manual ULSP entry done by the plant shift engineer/operator in the digital control system (DCS) of the GT. ULSP is filtered through a ramp rate filter, so that the step changes in ULSP are limited by the ramp rate and the resulting RULSP is a smooth ramp limited signal. Typically, the ramp rate limitation for each unit is 1%*Installed Capacity/min of the unit. RULSP is the signal that would be used by the NLDC AGC software as the basepoint for generating the AGC Set Point.

1.3. Cap_Max in MW

It is the gross unit capability to be updated by the power plant operator by distributing the ex-bus declared capability amongst the on-bar GTs and adding the respective auxiliary consumption. This shall be entered by the power plant operator in the DCS / HMI. To be entered for each GT. Any changes to the Cap_Max shall be carried out after giving prior intimation to the Nodal Agency.

1.4. Cap_Min in MW

It is the minimum limit to be entered by the power plant operator in the DCS / HMI. The value of Cap_Min would normally be 55%*(Cap_Max). To be entered for each GT. Any changes to the Cap_Min shall be carried out after giving prior intimation to the Nodal Agency.

Note: Cap_Max and Cap_Min values summed up for the total plant are used by the AGC software at NLDC to limit the final AGC Set Point before sending to the power plant. Cap_Max and Cap_Min are manually entered values (as decided during the October 2019 meetings with thermal power plants).

1.5. Distribution Factor

It is the fraction by which the power plant operator divides the AGC regulation signal (Delta P = Plant AGC Set Point – Plant RULSP) in between the Gts. This signal is available in the user interface of the AGC remote terminal unit (RTU). The sum of all distribution factors of GTs in a power plant must be 1 (this feature shall be automated by the power plant as per the detailed signal list). For achieving maximum economy, it is advisable to divide distribution factor equally between units operating under AGC Remote.

1.6. AGC Local/Remote

AGC Remote is the desired mode of operation for a SRAS Provider. However, during forced outages, SRAS Provider may take the units into Local after exchanging code with NLDC with an appropriate reason. A suitable user interface shall be developed by the instrumentation team at every power plant for taking units into Local/Remote. This is a single-point digital signal (0 – Local, 1- Remote). "Remote" means unit Delta P shall be added to RULSP before processing the signal for maximum and minimum limits and further sending it to master control. Thus, if a unit is in Remote, it is ready to accept and respond to AGC signals. "Local" means unit Delta P shall not be added to RULSP

1.7.Scaling Factor

It is the fraction (manual entry) by which the power plant can scale down the AGC DeltaP signal during combined cycle operation. For example, if 100 MW is the DeltaP signal for the plant, and scaling factor is 67%, 67 MW can be produced by all the GTs (and 33 MW is left to be produced by the STs). It is designed to be equal to the ratio of the desired total GT output to the total (GT+ST) output. **Note:** Considering practical advantage of immediate delivery of power by the GTs (output from STs is usually associated with a delay), **this scaling factor shall be input as 1**, i.e., no scaling down of AGC DeltaP given to GT is needed. The excess energy delivered by ST would also be accounted for weekly. The overall performance evaluation during the combined cycle operation would be based on the performance of the GTs.

1.7. Cycle Status

This signal is for flagging NLDC that CCGT is running under combined cycle. Manual entry. When under combined cycle, make **Cycle Status =1**, else zero. This data is used at NLDC for accounting ST contribution.

2. Activity list for different use cases

The actions while taking the units into Local, Remote, Shutdown, Communication failure, and AGC Suspending shall be automated as per the detailed signal list. For the units which are on bar and in "Local", Cap_Max = Cap_Min = ULSP shall be done. Distribution Factor shall be made zero for units which are in "Local". If CB is OFF, ULSP=0 shall be made for that unit. A new intermediate signal UADD may be configured. As many UADD signals may be derived for as many numbers of units.

UADD = (unit CB status ON,OFF) && (unit Local Remote status ON, OFF).

If either unit CB status=OFF or LR status=OFF, then UADD=0, else UADD=1.

An example table for a 3-unit plant is given below. The changes in Cap_Max, Cap_Min, Distribution Factor and ULSP may be automated based on the UADD state table.

	UADD				**Distribution factor**			**(Cap_Max, Cap_Min) Limits**		
S. No	**U 1**	**U 2**	**U 3**	**Logic**	**U 1**	**U 2**	**U 3**	**U1**	**U2**	**U3**
1	0	0	0	If U1ADD == 0 && U2ADD == 0 && U3ADD == 0	0	0	0	(ULSP, ULSP)	(ULSP, ULSP)	(ULSP,ULSP)
2	0	0	1	If U1ADD == 0 && U2ADD == 0 && U3ADD == 1	0	0	1	(ULSP, ULSP)	(ULSP, ULSP)	(Cap_Max, Cap_Min)
3	0	1	0	If U1ADD == 0 && U2ADD == 1 && U3ADD == 0	0	1	0	(ULSP, ULSP)	(Cap_Max, Cap_Min)	(ULSP,ULSP)
4	0	1	1	If U1ADD == 0 && U2ADD == 1 && U3ADD == 1	0	0.5	0.5	(ULSP, ULSP)	(Cap_Max, Cap_Min)	(Cap_Max, Cap_Min)
5	1	0	0	If U1ADD == 1 && U2ADD == 0 && U3ADD == 0	1	0	0	(Cap_Max, Cap_Min)	(ULSP, ULSP)	(ULSP,ULSP)
6	1	0	1	If U1ADD == 1 && U2ADD == 0 && U3ADD == 1	0.5	0	0.5	(Cap_Max, Cap_Min)	(ULSP, ULSP)	(Cap_Max, Cap_Min)
7	1	1	0	If U1ADD == 1 && U2ADD == 1 && U3ADD == 0	0.5	0.5	0	(Cap_Max, Cap_Min)	(Cap_Max, Cap_Min)	(ULSP,ULSP)
8	1	1	1	If U1ADD == 1 && U2ADD == 1 && U3ADD == 1	0.33	0.33	0.33	(Cap_Max, Cap_Min)	(Cap_Max, Cap_Min)	(Cap_Max, Cap_Min)

Note:

1. Power plants shall not place any limits on DeltaP per unit at their end. Note that imposing any limits on DeltaP will adversely impact power plant performance metrics during post-dispatch evaluation. Restriction on DeltaP can also cause ramp violations during ULSP changes by the power plant.

2. Always ensure that the ULSP value is in between Cap_Max and Cap_Min.

2.1. To take a generating unit into Remote (Open Cycle)

h) Make Distribution Factor = 0 for the GTs which are in Local.
i) Make Cap_Max = Cap_Min= ULSP for the GTs which are in Local.
j) Make ULSP = Cap_Max = Cap_Min = Distribution Factor =0, for all the off-bar GTs.
k) Distribute the Distribution Factor on the GTs under Remote. Ensure that the sum is 1.
l) Check if Cap_Max and Cap_Min have been entered as desired for the GTs which need to be under Remote.
m) Exchange code with NLDC. Maintain separate AGC codebook.
n) Always ensure that the ULSP value is in between Cap_Max and Cap_Min.

Date	Time	AREA AGC STATUS	NLDC CODE	POWER PLANT CODE	LOCAL/REMOTE		UNIT NO	REQUESTED BY (PLANT/NLDC)	CODE EXECUTION TIME	REMARKS	SIGN
					FROM	TO					

AGC code book format

2.2.To take a generating unit into Remote (Combined Cycle)

a. Make Distribution Factor = 0 for the GTs which are in Local.
b. Make Cap_Max = Cap_Min= ULSP for the GTs which are in Local.
c. Make ULSP = Cap_Max = Cap_Min = Distribution Factor =0, for all the off-bar GTs.
d. Distribute the Distribution Factor on the GTs under Remote. Ensure that the sum is 1.
e. Make Scaling Factor = 1.
f. Make Cycle Status = 1. (This is for flagging NLDC that CCGT is running under combined cycle)
g. Check if Cap_Max and Cap_Min are entered as desired.
h. Exchange code with NLDC. Maintain separate AGC codebook.
i. Always ensure that the ULSP value is in between Cap_Max and Cap_Min.

2.3.To take a generating unit into Local (Open Cycle / Combined Cycle)

e. Exchange code with NLDC (codebook format in Annexure-I). Maintain separate AGC code book.

- If the reason is a planned one, inform in advance
- If the reason is emergency, inform post facto
- If the reason is automatic local, then inform post facto

f. Make Distribution Factor = 0 for the units which are in Local.
g. Make Cap_Max = Cap_Min= ULSP for the units which are in Local.
h. Make sure to re-distribute Distribution Factor on the remaining units under Remote. Ensure that the sum is 1.

2.4.When a generating unit trips or is taken under shutdown, and the unit has been under Remote

d. Exchange code with NLDC for taking the GT into Local.
   - If the reason is a planned one, inform in advance
   - If the reason is emergency, inform post facto

g. Make Distribution Factor=0 for GTs which are in Local. Make sure to re-distribute Distribution Factor on the remaining units under Remote. Ensure that the sum is 1. For example, if the DF is 0.25 each for 4 units under Remote, and the fourth unit tripped, then DF will be 0 for the fourth unit and will be 0.33 for the remaining three units.
h. Make Cap_Max=0 for the tripped unit
i. Make Cap_Min=0 for the tripped unit
j. Make ULSP=0 for the tripped unit
k. Make sure that the CB status is being telemetered correctly as "Open =1"

2.5.There are three generating units; the first unit is off bar (RSD), the second unit is in Remote, and the third unit is in Local (for PG tests)

h. Distribution Factor = 0 for first and third units
i. Distribution Factor = 1 for second unit
j. Make Cap_Max=0 for off bar unit (only for first unit)
k. Make Cap_Min=0 for off bar unit (only for first unit)
l. Make ULSP = 0 for off bar unit (only for first unit)
m. Make Cap_Max = Cap_Min=ULSP, for the units which are in Local (only for third unit).
n. Must telemeter Cap_Max, Cap_Min, and ULSP for the second and third units

2.8.What to do after detecting Communication Failure / Communication Fluctuation.

e. Check ping status between plant router and plant RTU. If ping test fails, check for local issues at the end plant. Observe that DeltaP automatically becomes zero.
f. If ping test is through, inform NLDC for follow-up..

g. In case communication failure persists and/fluctuating, exchange code with NLDC and take units into Local.
h. After communication disruption is verified as rectified, then exchange code with NLDC and take units into Remote.

2.6. How to synchronize a new unit, while other units are running under AGC Remote in a power plant?

a. Before starting the unit
    i. Force CB status to “Open”, for that unit.
    ii. Force Cap_Max = Cap_Min = ULSP = Distribution Factor = 0, for that unit.
b. Start the unit and synchronize the unit. Maintain CB status as forced to “Open=1”.
c. After the unit has reached technical minimum
    i. Make Cap_Max = Cap_Min = ULSP. Release CB status to “Closed=2”.
    ii. To take this unit into Remote, follow section 2.1, as usual.

2.7. How to take a unit under planned outage, while other units are running under AGC Remote in a power plant?

a. Before ramping down the unit for planned outage,
    i. Force CB status to “Open=1”, for that unit.
    ii. Force Cap_Max = Cap_Min = ULSP = Distribution Factor = 0, for that unit.
    iii. Make sure to re-distribute Distribution Factor on the remaining units under Remote.
e. Exchange code with NLDC for taking the selected unit into Local.
f. Ramp down the unit and take the unit into outage.

Operations Guideline for Hydro Power Plants under AGC

Revision 0, Issued: 05th Dec 2022

This document provides the standard operating procedures to be followed during the continuous operation of the power plants under Automatic Generation Control (AGC) and attempts to answer the frequently asked questions.

Revision History

Rev-0: Original document – 05th Dec 2022

1. Controls Available with the Power Plant during AGC

User data entry of the below parameters is available for all the power plants under AGC. This data is received directly by NLDC from the power plants. Data can be entered through the relevant field in the user interface of the Remote Terminal Unit (RTU) or Digital Control System (DCS). These below seven signals are the "controls" available with the power plant during AGC operation.

1.1. **Unit Load Set Point (ULSP)** or the Base Point in MW

It is the unit-wise manual entry done by the plant shift engineer/operator in the digital control system (DCS) of the generating unit. ULSP is an gross value entered by the power plant shift engineer in the DCS for each time block calculated by adding auxiliary power consumption of the unit to the ex-bus schedule provided by the RLDC. Note that the ex-bus schedule is provided for the total power plant by the RLDC; this is distributed in between the on bar generating units by the plant operator considering on-site constraints. To be entered for each individual unit.

1.2.P1 in MW

It is the minimum value after synchronization to be entered by the plant operator in the DCS/HMI. To be entered for each individual unit.

1.3.P2 - P3 in MW (Forbidden zones or high cavitation zones)

P2 – P3 is the forbidden zone / cavitation zone for all the Francis turbine based hydro power plants entered by the power plant operator in the DCS/HMI. To be entered for each individual unit.

1.4.P4 in MW

It is the MW value up to which a unit can be overloaded. To be entered by the plant operator in the DCS/HMI for each individual unit.

1.5.Cap_Max in MW

It is the gross unit capability to be updated by the power plant operator by distributing the ex-bus declared capability amongst the on-bar generating units and adding the respective auxiliary consumption. This shall be entered by the power plant operator in the DCS / HMI. To be entered for each individual unit. During high hydro / spillage season, Cap_Max could be equal to the overload capacity, i.e., P4.

1.6. Cap_Min in MW

It is the minimum limit to be entered by the power plant operator in the DCS / HMI. To be entered for each individual unit

1.7.AGC Local/Remote

The manual choice to take the unit into local or remote is with the power plant shift engineer through DCS. A suitable user interface has been developed by the instrumentation team at every power plant for taking units into Local/Remote. This is a single-point digital signal (0 –

Local, 1- Remote). "Remote" means unit Delta P shall be added to RULSP before processing the signal for maximum and minimum limits and further sending it to master control. Thus, if a unit is in Remote, it is ready to accept and respond to AGC signals. "Local" means unit Delta P shall not be added to RULSP. This choice can be because of onsite problems, prolonged communication failure, etc.

Note: Hydro power plants shall be kept in Remote mode of operation after the units are scheduled by the RLDCs and are synchronized with the grid and their generation is stabilized. During other periods, the plants shall be maintained in Local. This switching between Local and Remote shall be carried out by exchanging code between NLDC and power plants.

2. Activity list for different use cases

All the above controls have to be used to run AGC during continuous operation. Below are the typical use cases/scenarios and action items during the same.

2.1. To take a generating unit into Remote

a) Check if P1, P2, P3 and P4 are entered as desired.

b) Inform NLDC if any other limit has to be imposed (e.g. to operate between P3 and P4, during high hydro season).

d) Exchange code with NLDC. Maintain separate AGC codebook.
e) Always ensure that the ULSP value is in between P1 and P4.

Date	Time	AREA AGC STATUS	NLDC CODE	POWER PLANT CODE	LOCAL/REMOTE		UNIT NO	REQUESTED BY (PLANT/NLDC)	CODE EXECUTION TIME	REMARKS	SIGN
					FROM	TO					

AGC code book format

2.2.To take a generating unit into Local

i. Exchange code with NLDC. Maintain separate AGC code book.
- If the reason is a planned one, inform in advance
- If the reason is emergency, inform post facto
- If the reason is automatic local, then inform post facto

2.3. What to do after detecting Communication Failure / Communication Fluctuation?

i. Inform NLDC for follow-up. Note that communication is provided by a third party (CTUIL/PGCIL) and not NLDC.
j. Observe that DeltaP automatically becomes zero
k. In case communication failure persists and/fluctuating, exchange code with NLDC and take units into Local.
l. After communication disruption is verified as rectified, then exchange code with NLDC and take units into Remote.

2.4 What to do if the AGC Setpoint is remaining in the forbidden zone?

1. Check if the forbidden zones (P2 and P3) telemetered to NLDC are correct.
2. Check if the communication between plant and NLDC is healthy. If not, take units into local immediately and exchange code with NLDC.
3. Check if the DeltaP has become zero after communication failure.
    - If DeltaP has not become zero, investigate why.
    - Sometimes the delay time can be 20-30 seconds for detecting communication break. Wait and check again.
    - Check if the setter feedback to NLDC is telemetered correctly and without delay (a delay of 2-4 seconds is acceptable).
        - Check AGC Setpoint and setter feedback signal to observe delay.
4. If setter feedback and communication both are healthy, inform NLDC to check the settings at their end.

3. Important Notes

1. Power plants shall not place any limits on DeltaP per unit at their end. Note that imposing any limits on DeltaP will adversely impact power plant performance metrics during post-dispatch evaluation. Restriction on DeltaP can also cause ramp violations during ULSP changes by the power plant.

2. Hydro power plants shall inform NLDC the operational range of limits in which the units have to be operated during high hydro season.

3. Sample format for providing information to NLDC

The AGC operation status for date-DD/MM/YY of the Power Stations are as below

Sl No	Name of Power Station	Unit Capacity (MW)	Operational Range	Reason
1	Plant-A	180	P3 to P4	Spillage
2	Plant-B	100	P3 to P4	Spillage
3	Plant-C	77	IC to P4	Spillage

Sl No	Name of Power Station	Unit Capacity (MW)	Operational Range	Reason
4	Plant-D	170	IC to P4 for 02 units	Spillage & heavy trash
5	Plant-E	35	No AGC	Silt Flushing
6	Plant-F	70	IC to P4	Spillage
7	Plant-G	130	IC to P4	Spillage

Annexure-VIII: Guidelines for operating intra-state generators/entities under AGC from NLDC

1. Intra-state generators shall submit the application to NLDC through appropriate RLDC for participating in SRAS through AGC.

2. Intra-state generators shall obtain standing consent (as per format SRAS-3) from respective SLDCs before participating in SRAS through AGC. SLDC shall ensure that proper scheduling, measurement (through SCADA), metering (through Special Energy Meters), accounting and settlement is in place before issuing consent to the concerned intra-state generator.

3. Intra-state generators shall ensure end-to-end communication in compliance to section 6 of this document.

4. Intra-state generators shall ensure the availability of appropriate hardware after checking the eligibility criterion as per section 5 of this document and Annexure-IV.

5. Intra-state generators shall provide the signals in compliance with section-7 of this document and Annexure-V of this document.

6. Intra-state generators shall provide the details as per format SRAS-1, including Energy charge / compensation charges.

7. Intra-state generators that would be connected to NLDC would be given the AGC Set Point using Regional Area Control Error (ACE). Detailed methodology of ACE calculation is given in Annexure-VI. For example, any intra-state generator in Uttar Pradesh that would be connected to NLDC after completing s.no.1 to s.no.6, would be given the AGC Set Point using the Northern Regional Area Control Error (ACE).

8. Standard Operating Procedure mentioned in Annexure-VII shall be applicable for intra-state generators also.

9. NLDC shall share the real-time AGC data of the intra-state generators through ICCP to RLDCs, and RLDCs shall share the same with the respective SLDCs.

10. In the case of intra-state generators participating in SRAS, Nodal Agency shall share the weekly SRAS 5-minute MWh and 15-minute MWh ex-bus quantum to the respective RLDC for onward transmission to the respective

SLDCs.

11. The respective SLDCs shall maintain the relevant scheduling data of intra-state entities during the SRAS operation (including but not limited to generating station-wise installed capacity, declared capacity, schedule, Un-Requisitioned Surplus (URS), generator wise SRAS schedules for up/down and requisitions from the generating stations).

12. SLDCs shall use the real time AGC MW data obtained through ICCP from the RLDCs, and incorporate it to the state's net schedule for the purpose of monitoring deviations.

13. AGC DeltaP quantum (SRAS-Up/SRAS-Down MW) for intra-state generators shall be incorporated in state's net schedule (with appropriate sign) for the purpose of computation of deviations by SLDC, RLDC, RPCs and by appropriate agency in the state. Hence, generation of the intra-state generator participating in SRAS would not be considered as deviation of the state. SLDCs and RPCs shall use the 15-minute SRAS MWh quantum data received from RLDC for implemented schedule preparation and deviation settlement.

14. SLDCs shall use the 15-minute SRAS MWh quantum data received from RLDC for deviation settlement.

15. **Weekly Accounts:** Weekly account data (5-minute MWh data and 15-minute MWh data) shall be shared by the intra-state generators through SLDCs to Nodal Agency in the format that would be provided after connection request. Section 17 of this document would be followed for weekly energy accounting.

16. **Accounting & Settlement:** For the intra-state generators, energy generated under AGC would be compensated through the Regional DSA Pool Account as per section 17 and section 18 of this document. For the intra-state generators, the settlement of payments towards SRAS-Up/SRAS-Down 15-minute MWh along with the performance based incentive payable for every 5-minute time interval, would be done by the RPC with the respective Regional Deviation and Ancillary Service Pool Account.

Annexure -IX: Detailed Methodology for Performance Assessment and Data Filtering

Good performance of the power plants under AGC is essential for effective frequency control. When the power plant is in Remote, the Actual MW should follow AGC Set Point for best performance. Performance metric is measured by plotting Output versus Input. CB status and Local/Remote status signals are considered in the calculations, so when the plant is in Local or not on bar, the performance is not evaluated.

Actual MW, RULSP, RGMO are available through SCADA every 4 seconds at gross level (before auxiliary consumption) from the dedicated RTU. The 4 seconds SCADA data is converted to five minutes average MW data.

Consider Circuit Breaker Status (CB Status) and LR Status (Local/Remote) status signals in calculations, although DeltaP calculated at the plant level automatically becomes zero when CB or LR Status is OFF. Take CB Status and LR Status at the start of each 5-minutes time block. Map CB status ON as 1 (Note that as CB is a double point signal, its ON value will be 2. Map the same to 1, for multiplication purposes in the formula). Similarly, Map CB Status OFF as 0.

Local Remote status (LR) is a single point signal. Map Local as 0 and Remote as 1.

For 'n' units,

- Output = $\sum_{i=1}^{n}((Actual\ MW_n - RULSP_n - RGMO_n) * CB_n * LR_n)$
- Input = $\sum_{i=1}^{n}((DeltaP_n) * CB_n * LR_n)$
- Plot a scatter plot of Output vs Input.
- 288 data points per SRAS Provider for one day would appear on the scatter plot. Each data point (dot) represents the 5-minute time block performance of the SRAS Provider.
- Add a Trend Line (Y=mX) to the plot with Intercept=0. Display equation on chart.
- Check the value of 'm' in Y=mX. Ideal performance would be Y=X.
- Say the equation is Y=0.8X, then consider the performance is 80% for that day. Performance would be evaluated for each day of the week. There would be one performance metric value calculated for the whole day for each SRAS Provider (see Format SRAS-2).
- If the RGMO MW input to the governor data is not telemetered / provided by the power plant, consider the value as zero.
- Note that a poor R^2 value (< 0.5) indicates that the trend line fits with a low confidence, and there may be some external factors, creating outliers, disturbing the actual response. Nodal Agency would keep monitoring and intimate the SRAS Provider to investigate the possible causes, if a sustained low value of R-square is noted. Presently, R^2 value is not being used in the

incentive calculation process to keep the mechanism simple, however, R^2 would be constantly reviewed by the Nodal Agency for providing further feedback to CERC.

- If performance is more than 100%, clamp the value to 100%. More than 100% performance may also indicate poor control tuning and any other issue, Nodal Agency would keep monitoring and intimate the SRAS Provider to investigate the possible causes, if sustained over response is noted.

Then a scatter plot of Output vs Input is prepared similar to as shown below. A trend line (to fit Y=mX) to the plot is added. The data set is 5-minute data for a sample day. In the below figure, the ideal expectation would be y=x; output response is the same as the input command. In the sample example below, the performance of the SRAS Provider is 94.2% for that particular day.

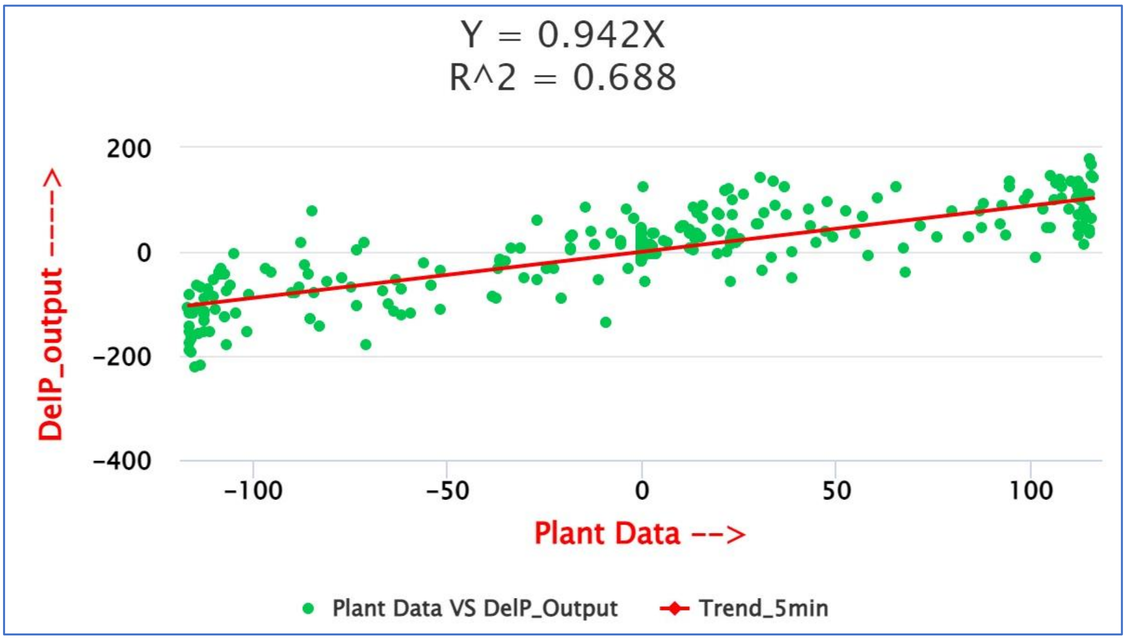


Figure-1: Sample performance of an SRAS Provider under AGC for a day

As this process has to be carried out for each day, at the end of every week, sufficient automation has been custom built around the AGC software and historian for the retrieval and processing of data. As a result, there would be minimal or no manual intervention while carrying out these calculations.

Filtering Output MW data through Normal Distribution

The Output MW data is derived from Actual MW, RULSP and RGMO MW, which are all telemetered SCADA signals and may contain some noise. The below simple method would be used for filtering the Gross Output MW data while calculating the performance of the power plants under AGC.

1. Convert the raw 4s MW data to 5 min average MW data using the historian and scripts
2. Collect the 5 min average MW data into MS Excel files
3. Read the gross output MW 5 min average MW data into NoSQL database
4. Read the gross output data into array and create a copy
5. Calculate the Mean and Standard Deviation (σ) of the data of gross output MW
6. Calculate
    a. (Mean-3*Standard Deviation)
    b. (Mean+3*Standard Deviation)
7. If the raw copy data >= 6.a. and raw copy data <= 6.b., then don't change the data.
   Else replace the raw copy data with the implemented DeltaP plant data.

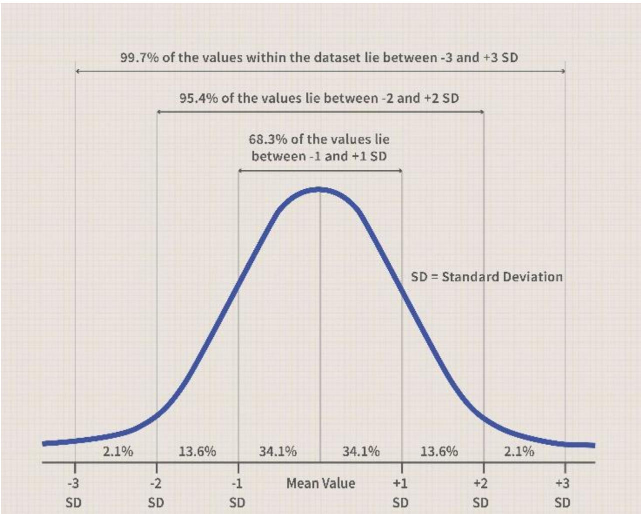
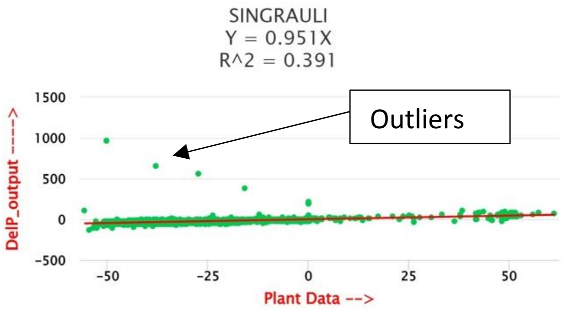
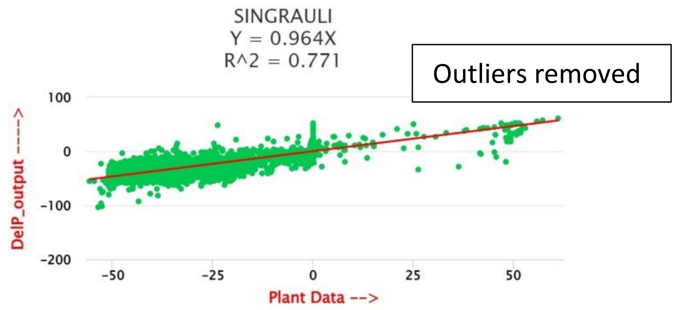


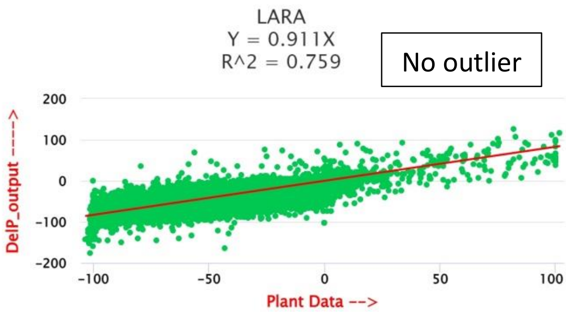
Figure 2: Normal Distribution

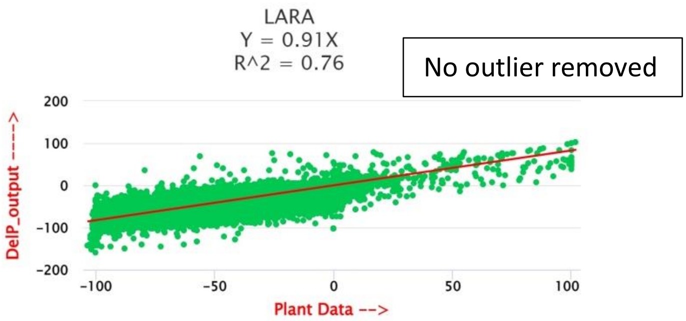
8. Because of the above procedure, 99.7% values remain unchanged. The 0.3 % of the outliers in the SCADA data would be replaced with the implemented DeltaP input data, thereby improving the confidence level of the linear trend line. The resulting data may show either a higher, lower or the same performance, varying on a case-to-case basis. Examples of power plant performance before after this data filtering is given below.

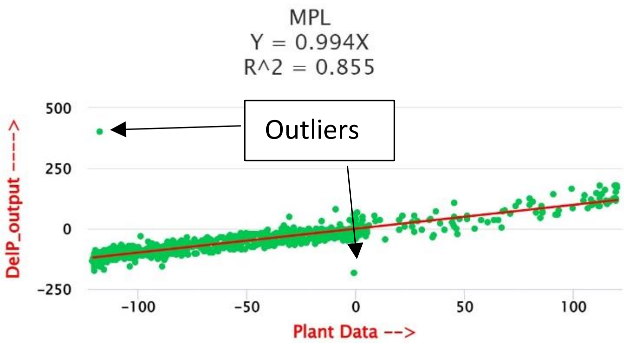
Before filtering **After filtering**

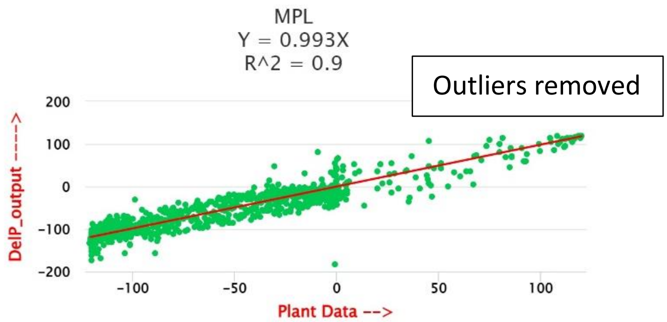












Annexure -X: Undertaking on Cyber Security

UNDERTAKING ON CYBER SECURITY I, ________________________ (Name of Plant I/c) on behalf of_____________________________________ (Organisation Name), hereby declare that

a) I hereby unconditionally accept and ensure all the cyber security measures at plant end which are mentioned in the subsequent points

i) Only authorised equipment (AGC, computer (HMI) and Router-cum firewall) required for AGC functioning will be connected.

ii) Internet access is blocked in the computer used for AGC HMI and Antivirus is installed and patches will be updated regularly in the HMI computer.

iii) No Internet interface will be provided in the network used for the AGC purpose.

iv) Router cum firewall will be dedicatedly used for communication with NLDC AGC system. v) RTU remote access cable will be connected only for absolutely essential works and will be disconnected after work.

vi) All the ports other than 2404 are blocked in the router-cum-firewall.

vii) All the IPs other than IPs provided by NLDC are blocked in the firewall.

viii) DCS is not connected with any IT equipment.

ix) Application whitelisting at AGC server & HMI shall be implemented with alerts feature in case of any unwanted application.

x) Checks shall be performed by IT experts regularly at power plants for tracing any unwanted processes.

b) We will comply with all the applicable/prevailing statutory provisions, laws, acts and Government orders amended/notified during the period of AGC operation.

c) We have disclosed all the information related to connectivity of equipments within AGC network and information so provided is true, correct, complete and nothing has been concealed thereof.

d) We understand that, in situation of non-compliance of cyber security measures and incorrect/false declaration, the present integration of plant will be disconnected from AGC network by POSOCO without any prior information.

Dated:
Place:

Yours Faithfully,

Signature: ______________
Name:
Contact:
Address:

<u>Format-SRAS1: SRAS Settlement Account by RPC</u>

(To be issued by concerned RPC)

SRAS Account for Week: ……………………………

Sl No	SRAS Provider(s)	SRAS-Up (MWh) (A)	SRAS-Down (MWh) (B)	Net Energy (MWh) (C)=(A)-(B)	Energy Charges/ Compensation charges (Rs.) (D)	Actual performance (%)	Incentive Rate (paise/kWh)	Incentive (Rs) (E)	Total Charges (Rs.) **(F)=(D) +(E)**
1									
2									
3									
…									
…									
	Total								

<u>Format-SRAS-2: Actual Performance Statement by RPC</u>

(To be issued by concerned RPC)

Week: …………………………….

Sl No	SRAS Provider(s)	Date1	Date2	Date3	Date4	Date5	Date6	Date7	Remarks (Disqualification period)
		Actual performance (%)	Actual performance (%)	Actual performance (%)	Actual performance (%)	Actual performance (%)	Actual performance (%)	Actual performance (%)	
1									
2									
3									
…									
…									
	Total								

Format SRAS-3: Standing Consent by SLDC to Intra-State SRAS Provider

Ref.No. …………………………………………………. Dated …………………

1. Name of SLDC issuing Standing Consent:
2. Region: NR / WR/ SR/ ER/ NER:
3. Entity seeking consent from SLDC to become a Secondary Reserve Ancillary Services (SRAS) Provider:
4. Status of Entity (CPP/IPP/State Power Plant/DISCOM, etc.):
5. Point(s) of connection:
6. Validity Period (From date and To date):

Declaration:

The intra-state generator shall fulfill the below conditions:

I. Scheduling, measurement (through SCADA), metering (through Special Energy Meters), accounting and settlement is in place for the above SRAS Provider.
II. Intra-state SRAS Provider shall ensure end-to-end communication in compliance to the Detailed Procedure.
III. Intra-state SRAS Provider shall ensure the availability of appropriate hardware after checking the eligibility criterion in compliance to the Detailed Procedure.
IV. Intra-state SRAS Provider shall provide the signals in compliance to the Detailed Procedure.
V. Intra-state generators shall provide the technical and commercial details as per the Detailed Procedure.
VI. Standard Operating Procedure mentioned in the Detailed Procedure shall be followed at all times by the intra-state SRAS Provider.
VII. Weekly account data (5-minute MWh data and 15-minute MWh data) shall be shared by the intra-state SRAS Provider through SLDCs to Nodal Agency in the format that would be provided after connection request.
VIII. Any change in the contents of the Standing Consent shall be conveyed to the party to whom Standing Consent was given, within 24 hours. In such cases all the stakeholders shall be informed simultaneously.

Intra-state generating entity shall be aware that:

1. Intra-state generators that would be connected to NLDC would be given the AGC Set Point using Regional Area Control Error (ACE).
2. NLDC shall share the real-time AGC data of the intra-state generators through ICCP to RLDCs, and RLDCs shall share the same with the respective SLDCs.
3. In the case of intra-state generators participating in SRAS, Nodal Agency shall share the weekly SRAS 5-minute MWh and 15-minute MWh ex-bus quantum to the respective RLDC for onward transmission to the respective SLDCs.

4. The respective SLDCs shall maintain the relevant scheduling data of intra-state entities during the SRAS operation (including but not limited to generating station-wise installed capacity, declared capacity, schedule, Un-Requisitioned Surplus (URS), generator wise SRAS schedules for up/down and requisitions from the generating stations).
5. SLDCs shall use the real time AGC MW data obtained through ICCP from the RLDCs, and incorporate it to the state's net schedule for the purpose of monitoring deviations.
6. AGC DeltaP quantum for intra-state generators shall be incorporated in state's net schedule (with appropriate sign) for the purpose of computation of deviations by SLDC or appropriate agency in the state. Hence, generation of the intra-state generator under AGC would not be considered as deviation of the state.
7. SLDCs shall use the 15-minute SRAS MWh quantum data received from RLDC for deviation settlement.
8. Weekly Accounts: Weekly account data (5-minute MWh data and 15-minute MWh data) shall be shared by the intra-state generators through SLDCs to Nodal Agency in the format that would be provided after connection request. Section 17 of this document would be followed for weekly energy accounting.
9. Accounting & Settlement: For the intra-state generators, energy generated under AGC would be compensated through the Regional DSA Pool Account as per the Detailed Procedure. For the intra-state generators, the settlement of payments towards SRAS-Up/SRAS-Down 15-minute MWh along with the performance based incentive would be done by the RPC with the respective Regional Deviation and Ancillary Service Pool Account.

Standing Consent is hereby provided to the intra-state generator mentioned above seeking to participate in the Secondary Reserve Ancillary Services (SRAS) mechanism in accordance with the Detailed Procedure prepared in compliance to the Central Electricity Regulatory Commission (Ancillary Services) Regulations, 2022, subject to the declaration made above.

Signature:
Name:
Designation:
(Authorized Signatory)
Phone No:

Place:

Date:

Frequently Asked Questions (FAQs)

a. Will AGC overload the plant beyond full load?

Ans: No. When the plant is running at full load (Cap_Max), only down regulation is possible. In case of coal mill tripping, decrease Cap_Max.

b. Will AGC overload the plant below technical minimum?

Ans: No. When the plant is running at technical minimum (Cap_Min), only up regulation is possible. In case of any stability issues, increase Cap_Min.

c. Why is the DeltaP positive when the frequency is higher than 50 Hz?

Ans: AGC is secondary frequency control and is inherently a slow control in which the AGC Set Point changes direction only with the plant-defined ramp rate. Also, AGC software at NLDC uses a Proportional-Integral-Derivative (PID) controller which results in a Smoothened Area Control Error (Smooth ACE), which acts as an input to AGC, instead of raw ACE. Whereas ACE and frequency change their direction instantaneously, Smoothed ACE is the output of the PID controller and carries the accumulated integral error. This results in a definite time lag (few minutes) between the change of direction of Smooth ACE and direction of frequency. Although PID controller adds time lag, it is necessary to cover the steady state error of frequency and it also prevents random changes to the plant AGC Set Point. Correct procedure for analysis would be to plot the data over a period of time when the AGC has been in Remote, rather than looking at instantaneous values of frequency and DeltaP.

d. Is Ramp Rate factored by AGC?

Ans: Yes. Ramp Rate as declared in the NLDC/RPC Format is used by the AGC software. That Ramp Rate divided by number of units is entered for every on-bar unit. Say X MW/min is the ramp rate of the power plant. AGC Set Point gets updated every 4 seconds with an incremental ramp of (X*4/60) MW. For example, a 500 MW unit has a ramp rate of 5 MW/min, then the AGC Set Point can only move every 4 seconds with an incremental ramp of 0.33 MW. Both Up and Down Ramp Rates are considered.

e. When should the MWh account be sent?

Ans: Please send MWh account on every Monday for the previous week from Monday to Sunday. Use only NLDC specified format.

f. **In post-despatch calculations by commercial teams, (Avg RLDC Schedule MW + Avg AGC MW) > DC onbar MW (or) In post-despatch calculations by commercial teams, (Avg RLDC Schedule MW + Avg AGC MW) < Technical Minimum MW (or) There is ramp rate violation in Average MW data.**

Ans: Gross AGC Set Point always stays in between Cap_Max and Cap_Min. Avg AGC MW is calculated by subtracting the normative auxiliary consumption from the gross Avg AGC DeltaP MW, which can be positive or negative. If this number is added to the Avg RLDC Schedule MW, then this number might exceed DC on bar MW or might become less than Technical Minimum MW. This happens not because AGC has violated limits, but because of the regular dispatch process. ULSP entry is a manual entry by the power plant shift engineers. (Average ULSP MW – NAC) is never exactly equal to the Average RLDC Schedule MW for the 15-minute time block. As AGC uses RULSP every 4 seconds as its base for providing the Set Point, AGC might utilize any margin actually present between RULSP and Cap_Max in the real time. Since there is no physical limit violation by the AGC Set Point MW at any time, this exceedance in average calculation can be ignored unless the difference is very large.

g. **Will there be a ramp rate violation when the power plant changes ULSP?**

Ans: No. There will not be any ramp rate violation by AGC when the power plant changes ULSP. Ramp Rate as declared in the Ancillary Services Format is used by the AGC software. That Ramp Rate divided by number of units is entered for every on-bar unit. Say X MW/min is the ramp rate of the power plant. AGC Set Point gets updated every 4 seconds with an incremental ramp of (X*4/60) MW. For example, a 500 MW unit has a ramp rate of 5 MW/min, the AGC Set Point can only move every 4 seconds with an incremental ramp of 0.33 MW. As RULSP is used as base point while issuing AGC Set Point, even though step changes are made to the ULSP, AGC Set Point would move in a ramp limited manner. Restriction on DeltaP can cause ramp violations during ULSP changes by the power plant.

h. **Can DeltaP of two different commercial stages of the same power station complex come in opposite directions at the same time?**

Ans: It can happen whenever DeltaP is moving from positive direction to negative in response to system conditions or vice versa. The first power plant can have greater up/down margin (in the order of 40-50 MW) than the other power plant (in the order of 4-5 MW) for the time under consideration. Therefore, DeltaP for the first power plant could go up/down till 40-50 MW and 4-5 MW only for the second power plant. Hence, DeltaP for first power plant takes more time for changing direction but for the second power plant, it does quickly (given that the ramp rate per unit of both the stages are nearly same, say Stage-1: 4.6MW/min; Stage-2: 4.7 MW/min). Till the time DeltaP of the first plant changes direction, it appears that both the stages are receiving AGC command in opposite directions, although AGC is functioning as intended. Here the actual direction vector of both the plants is same, even though the magnitude may appear in opposite direction for a brief period of time. So, power stations of the same complex may note this situation while analyzing/comparing data.